DIRECT TESTIMONY OF
ERIC H. BELL, P.E.
ON BEHALF OF
DOMINION ENERGY SOUTH CAROLINA, INC.
DOCKET NO. 2019-226-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Eric H. Bell. My business address is 220 Operation Way, Cayce, South Carolina. I am Manager of Economic Resource Commitment for Dominion Energy South Carolina, Inc. ("DESC" or the "Company").[1]

Q. STATE BRIEFLY YOUR EDUCATION, BACKGROUND, AND EXPERIENCE.

A. I am a graduate of the University of Texas with a Bachelor of Science degree in Electrical Engineering and am licensed in South Carolina as a Professional Engineer. Following graduation, I served in the United States Navy as a Nuclear Submarine Officer. In 1994, I began my career with South Carolina Electric & Gas Company ("SCE&G") as Assistant Plant Engineer and, in 1997, was promoted to Operations Planner. From 2001 to 2008, I engaged in economic resource

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[1] SCE&G changed its name to Dominion Energy South Carolina, Inc. in April 2019, as a result of the acquisition of SCANA Corporation by Dominion Energy, Inc. For consistency, I use "DESC" to refer to the Company both before and after this name change.

commitment efforts and, in 2008, I assumed my current role as Manager of Economic Resource Commitment. In this position, I am responsible for managing and optimizing generation fleet operations to provide reliable, least-cost energy to DESC customers. Among other things, my responsibilities include participating in fuel purchasing decisions, unit commitment, and the coordination of activities and system data with power marketing, transmission system control, maintenance scheduling, and natural gas supply. Since June of 2019, I have also been responsible for DESC's generation planning, which includes managing the development of the Integrated Resource Plan ("IRP").

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (THE "COMMISSION")?

A. Yes, I have testified before in a prior proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor DESC's 2020 IRP ("2020 IRP") into evidence and provide an overview concerning its goals, preparation, contents, methodologies, and key conclusions. I also introduce the testimony of the other Company witnesses:

1. Therese Griffin is the Manager of Energy Efficiency and Demand Management for DESC. As Manager of Energy Efficiency and Demand Management, Ms. Griffin leads the planning and implementation of DESC's

residential, commercial, and industrial energy efficiency demand-side management ("DSM") programs. Ms. Griffin is also responsible for integrating the Company's energy efficiency efforts with its renewable energy programs and customer assistance department. Ms. Griffin's testimony will provide an overview of DESC's current suite of DSM programs and the customer energy efficiency measures and demand response measures that were considered in formulating the IRP.

2. James W. Neely, P.E. is the Senior Resource Planning Engineer for DESC. He is responsible for modeling DESC's electric system in order to calculate avoided costs, determine the least cost resource plan, forecast fuel costs, and evaluate changes to DESC's electric generation. Mr. Neely will testify with specificity as to the modeling used, and the eight resource plans generated, in the 2020 IRP.

3. Joseph M. Lynch, Ph.D. is the Manager of Resource Planning for DESC. He is responsible for managing the department that produces DESC's forecast of energy, peak demand, and revenue. Dr. Lynch is also responsible for overseeing DESC's load research program. Dr. Lynch will testify to the load forecast as an input to the IRP and will discuss DESC's reserve margin policy.

Q. PLEASE DESCRIBE THE COMPANY'S 2020 IRP.

A. DESC's 2020 IRP, as updated, is attached to my testimony as Exhibit __ (EHB-1). It was prepared in conformity with the requirements of S.C. Code Ann. § 58-37-40 (the "IRP statute") using methodologies that are well-recognized in the industry. The resource plans it models define a broad range of possibilities for meeting the future needs of DESC's electric customers reliably, efficiently, and economically and include the most relevant technologies available for that purpose. The 2020 IRP models the costs to customers across a broad range of resource plans and includes assessments of the sensitivity of those plans to key variables such as natural gas prices, costs imposed on carbon dioxide ("CO_2") emissions, and variations to load impact through DESC's investment in DSM programming. In all, the IRP models the results for customers against eight resource plans and 64 distinct scenarios. As the statute requires, the IRP also presents information concerning the anticipated investment in transmission assets to ensure that DESC can meet its customers' energy needs reliably and efficiently. The 2020 IRP appropriately considers all matters specified under S.C. Code Ann. § 58-37-40 and meets all statutory requirements for approval by the Commission.

Q. WHEN WAS THE 2020 IRP PREPARED?

A. The 2020 IRP was prepared beginning in late 2019 and was completed in February 2020. The modeling it contains is based on conditions that were known or forecasted at that time. DESC's planning team will perform the annual IRP update beginning in late 2020 for filing in February 2021 based on conditions current at that time and any instructions from the Commission that emerge from this proceeding.

Q. HAS DESC MADE, OR IS DESC PLANNING TO MAKE, ANY DECISIONS TO ADD OR RETIRE GENERATION RESOURCES BASED ON THE 2020 IRP?

A. No. DESC does not anticipate that any decisions to add or retire generation resources will be made based on the results of the 2020 IRP. All modeling shows that DESC has sufficient capacity to meet customers' needs without adding additional generation for a number of years. This is due in large part to the large amount of generation that has been added to DESC's system in recent years including solar and the Columbia Energy Center combined cycle unit. While DESC is considering the early retirement of certain coal-fired facilities in 2028, the decision to proceed with those early retirements has not been made at this time.

Q. DO GENERATION, TRANSMISSION, OR DISTRIBUTION MODERNIZATION PLANS DEPEND ON THE MODELING CONTAINED IN THE 2020 IRP?

A. No. As the 2020 IRP shows, DESC continues to evaluate the possibility of modernizing its existing internal combustion turbine ("ICT") fleet, which includes a number of older technology units. DESC is also modernizing its transmission and distribution system to better accommodate renewable and distributed generation and to upgrade the automation and control features. However, these projects are not intended to meet upcoming generation supply needs identified in the 2020 IRP, and the decisions concerning them are not dependent on the results of the modeling contained in the 2020 IRP.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony discusses each item that the IRP statute requires to be included in an IRP and each factor that the Commission is empowered to consider in approving an IRP. For the Commission's convenience, footnotes have been inserted referencing the specific statutory provision being addressed in each section of the testimony.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP MEETS THE REQUIREMENTS OF THE IRP STATUTE FOR "A LONG-TERM FORECAST OF THE UTILITY'S SALES AND PEAK DEMAND UNDER VARIOUS REASONABLE SCENARIOS."[2]

A. Section I of the 2020 IRP (pp. 9–17) provides DESC's forecast for sales and peak demand for the 15-year IRP planning horizon. The medium case reflects an annual growth rate of 0.5% in energy sales and a firm peak demand growth rate of 0.7% for both summer and winter. The 2020 IRP further evaluates the sensitivity of each resource plan to variations in load growth and energy demand through the analysis of low and high DSM scenarios. The medium case assumes that DESC achieves the current projection for reducing annual energy consumption through

[2] S.C. Code Ann. § 58-37-40(B)(1)(a)

DSM, among non-opt out customers, by 0.7%, with a corresponding reduction in peak demand.[3] The low DSM case assumes only a 0.33% annual reduction in energy sale. This reflects the amount of DSM savings that ICF Resources, LLC ("ICF") estimated would occur if DESC continued to implement its suite of DSM programs prior to the doubling of DSM investment beginning in 2020. ICF prepared that estimate as part of the *Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan Final Report* ("2019 Potential Study") which was presented to the Commission in Docket 2019-239-E. The high DSM case projects a 1.0% annual reduction in energy sales from those programs. Both the medium and high DSM cases assume that DESC achieves a 43 megawatt ("MW") reduction in winter peak demand due to the implementation of additional peak clipping programs that take advantage of Advanced Metering Infrastructure ("AMI"), which is currently being installed across the system.

The medium case growth rates for energy sales and demand were derived from economic analysis of historical sales and peak demand data in order to identify the relationship between growth rates in the economy and growth in demand and energy sales for customer classes, and for businesses, within certain standard industrial classification codes. Specific consideration was given to the impact of wholesale loads on historical and projected growth rates, and to the increasing

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[3] All DSM reduction percentages are net of opt-out customers and available in detail in the 2019 Potential Study.

impact of federal appliance and lighting efficiency standards and other efficiency gains on energy sales and demand. Similarly, a sensitivity study was prepared to assess the range of potential new loads from electric vehicles based on scenarios reflecting high, medium, and low penetration of electric vehicles in DESC's service area going forward.

Additional details concerning the energy sales and peak demand forecasts, scenarios, and sensitivities can be found in the testimony of our forecast witness, Dr. Joseph Lynch, and his Exhibits ___ (JML-1, 2 & 3). As he testifies, the 2020 IRP provides a complete and well-considered long-term forecast of DESC’s sales and peak demand under various reasonable scenarios.

Q. DOES DESC'S 2020 IRP INCLUDE “SEVERAL RESOURCE PORTFOLIOS DEVELOPED WITH THE PURPOSE OF FAIRLY EVALUATING THE RANGE OF DEMAND SIDE, SUPPLY SIDE, STORAGE, AND OTHER TECHNOLOGIES AND SERVICES AVAILABLE TO MEET THE UTILITY'S SERVICE OBLIGATIONS” AS THE IRP STATUTE REQUIRES.[4]

A. Yes. DESC’s 2020 IRP identifies and presents eight resource plans that fairly reflect the range of demand-side, supply-side, storage, and other technologies and services that are available to meet the utility's service obligations. Each is tested

[4] S.C. Code Ann. § 58-37-40(B)(1)(e)

for its sensitivity against a range of price, environmental, and DSM-based load variables.

Q. DOES DESC'S 2020 IRP EVALUATE "DEMAND-SIDE . . . TECHNOLOGIES AND SERVICES" AS THE IRP STATUTE REQUIRES?[5]

A. Yes. As Company Witness Therese Griffin will explain in more detail, the evaluation of DESC's current DSM programs is based on ICF's 2019 Potential Study prepared by ICF. ICF is a nationally recognized expert in preparing and implementing DSM programs. The 2019 Potential Study evaluated over ten thousand individual DSM measures for potential implementation. It assessed which of those measures and combinations of measures were economically viable if implemented in DESC's service territory, specifically, whether they would generate sufficient savings for customers and the electrical system to justify their cost. The study further assessed the likely acceptance and penetration rates of those programs given DESC's customer base and demographics, and which programs would be supported by trade allies and practical to implement over a five-year program implementation horizon.

Based on the 2019 Potential Study, DESC proposed doubling its current expenditures on DSM programs. It targets increasing the reduction in annual energy

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[5] S.C. Code Ann. § 58-37-40(B)(1)(e)(i)

sales by 0.7% compared to a reduction of 0.33% in annual energy sales that would likely have been achieved under the prior DSM plan.

In Order No. 2019-880, dated December 20, 2019, the Commission approved DESC's proposed suite of DSM programs with certain modifications and expansions. To provide for consistency and stability in the implementation of the new DSM program, the Commission specifically ordered that the approved DSM program would not be subject to changes based on regulatory challenges for the five-year period ending in 2024. Section II (A) of the 2020 IRP (pp. 18-23) summarizes DESC's DSM programs as approved by the Commission in Order No. 2019-880, including energy efficiency and demand response components. Ms. Griffin's testimony provides further information concerning these programs.

Q. ARE THE LOAD GROWTH PROJECTIONS MODELED IN DESC'S 2020 IRP CONSISTENT WITH ITS COMMISSION-APPROVED DSM PROGRAM?

A. Yes. The 2020 IRP modeling assumes as its medium case the level of DSM-related reduction in energy sales of 0.7%, among non-opt out customers, annually, which is the level determined to be reasonable and practical in the 2019 Potential Study and consistent with the DSM plan adopted by the Commission. As a sensitivity check, the eight resource plans were also evaluated against a level of potential DSM impact that is more than 40% higher than the reduction in retail energy sales found to be cost effective and practical by the Commission in its 2019 order. The high DSM case assumes a 1.0% annual reduction in energy sales due to DSM. The costs and programmatic requirements for achieving impacts at DSM levels of 1.0% were not quantified or supported in the 2019 Potential Study. Instead, as Company Witness Griffin testifies in greater detail, approximately 10,000 measures were evaluated for cost effectiveness and practicality. Those measures that were determined to be practical and cost effective did not support projecting DSM impacts at a 1.0% level. For purposes of this IRP, the 1.0% impact level is a hypothetical level that is assumed as the high DSM case for purposes of a sensitivity analysis. The associated costs were extrapolated from existing data but not verified. The inclusion of this case in the IRP in no way indicates that DESC believes that it is reasonable or achievable.

The 2020 IRP also modeled the eight resource plans assuming only a 0.33% reduction in retail sales and corresponding reduction in demand due to DSM. This is the amount of reduction in retail sales that the 2019 Potential Study determined would have been achievable absent DESC's doubling of investment in DSM programs beginning in 2020.

Q. DO THESE DSM-RELATED LOAD REDUCTIONS INCLUDE THE LOAD REDUCTIONS CAUSED BY GENERAL INCREASES IN ENERGY EFFICIENCY THROUGHOUT THE ECONOMY?

A. No. The DSM-related reductions are anticipated to occur over and above those caused by energy efficiency increases in the economy generally. Energy efficiency standards for lighting and appliances, building envelopes, construction techniques, and building codes are driving reductions in retail sales apart from DSM programs. These non-DSM reductions are reflected in the underlying load assumptions used in modeling the eight resource plans and are independent of the DSM-related reductions modeled in the low, medium, and high DSM energy sales projections. As the 2019 Potential Study indicates, these increases in general efficiency standards makes it harder for DESC's DSM programs to achieve additional incremental reductions in energy sales going forward.

Q. WERE THE MODELS EVALUATED IN LIGHT OF ADDITIONAL PEAK CLIPPING MEASURES TO BE IMPLEMENTED USING ADVANCED METERING INFRASTRUCTURE?

A. Yes. Each of the eight resource plans was evaluated in light of peak clipping measures that DESC plans to implement when sufficient penetration of AMI has been achieved. DESC is rolling out AMI on a three-year schedule. The medium and high DSM cases assume that future AMI-based programs offset 43 MW of winter peak demand. To be consistent with prior practice, the 43 MW of peak winter load reduction was modeled as a generation supply resource with zero energy cost available during the hours of winter peak.

Q. DOES DESC'S 2020 IRP EVALUATE "SUPPLY SIDE TECHNOLOGIES AND SERVICES" AS THE IRP STATUTE REQUIRES?[6]

A. Yes. Section II (B)(1)-(4) of the 2020 IRP (pp. 23–36) summarizes DESC's analysis of a broad range of supply-side technologies and services available to meet its utility service obligations. That section summarizes DESC's analysis of the existing supply-side technologies currently in use on its generating system, as well as emerging renewable technologies, and yet-to-be-deployed technologies such as battery storage that may be available over the 15-year IRP. The technologies identified for potential future deployment include battery storage ("Battery Storage"); utility self-build solar ("Solar"); solar generation built and financed by third parties and purchased through purchase power agreements ("PPAs"); combined cycle heavy-frame natural gas-fired internal combustion turbines coupled with a heat recovery steam cycle ("CC 1-on-1"); large simple-cycle heavy-frame natural gas-fired internal combustion turbines ("ICT Frame J"); and smaller aero-derivative simple cycle gas-fired internal combustion turbines ("ICT Aero").

Section II (B)(5) of the 2020 IRP (pp. 37–51) presents eight separate resource plans that apply combinations of these available supply side technologies to meet the needs of DESC's customers as demands grow and as existing coal-fired generation stations are retired. The 2020 IRP models eight resource plans that each

[6] S.C. Code Ann. § 58-37-40(B)(1)(e)(i)

of which reflect implementation of a different suite of supply options over a 15-year period. As the IRP statute requires, each of these resource plans is evaluated against multiple sensitivity cases reflecting assumptions as to high, medium and low natural gas prices; high, medium, and low impacts of DSM; and the presence or absence of CO_2 emissions charges at $25/ton. The results show the comparative cost to customers of these eight resource plans modeled under a total of 64 distinct scenarios each of which was evaluated to create a levelized cost over a 40-year period.

Q. DOES DESC'S 2020 IRP MEET THE REQUIREMENTS OF THE IRP STATUTE FOR INFORMATION CONCERNING "TYPE OF GENERATION TECHNOLOGY PROPOSED FOR THE GENERATION FACILITY CONTAINED IN THE PLAN AND THE PROPOSED CAPACITY OF THE GENERATION FACILITY?" [7]

A. Yes. Information concerning the types and capacities of generation proposed in each resource plan is clearly provided in the IRP. For example, Resource Plan 2 is the least cost resource plan under base assumptions. Resource Plan 2 assumes that the currently committed solar projects will be completed in 2020 and 2021 but does not propose any additional generation facilities be added to DESC's system during the 15-year IRP planning horizon. It also does not assume the early

[7] S.C. Code § 58-37-40(B)(1)(b) and (g).

retirement of any existing coal-fired generation resources. Modeling the system based on those assumptions shows that DESC would not need to add long-term to meet the required base capacity reserve margin during the 15 years covered by the resource plan. Although there is no new generation capacity proposed under that supply plan, the IRP nonetheless specifies the types and capacity of the existing generation resources that will be used to meet customers' needs.

Resource Plan 8 results in the greatest lowering of DESC's CO_2 emissions and most rapid reduction in reliance on coal-fired generation. This plan models the effects of retiring 1,294 MW of coal-fired generation capacity in the winter of 2028 and simultaneously adding 1,076 MW of natural gas-fired capacity. The replacement capacity modeled in this plan consists of a CC 1-on-1 unit (553 MW), and two ICT Frame J units (523 MW). Future load growth is met by adding tranches of 100 MW of Storage during the winter of 2031, 2033, and 2034; and, two more ICT Frame J units (523 MW) in 2036. Additional Solar in the total amount of 2,100 MW is added in years 2027 through 2048. The plan further reduces reliance on coal-fired generation by assuming that Cope Station is converted to gas-only operation.

Q. WHY DOES THE TABLE PRESENTING RESOURCE PLAN 8 FOUND ON PAGE 51 OF THE IRP SHOW DIFFERENT CAPACITY VALUES FOR ADDITIONAL SOLAR GENERATION BEGINNING IN 2027?

A. In the table presented on page 51 of the 2020 IRP, as updated, Solar generation is added in 50 and 100 MW blocks. Because winter peaks occur at or near sunrise, each 50 or 100 MW block of Solar added to the system results in 0 MW of winter peak capacity and between 4 and 8.8 MW of summer capacity, as listed on that table. The 50 to 100 MW blocks of Storage capacity are shown to have a full 50 or 100 MW impact on winter peak capacity needs and can be used to allow energy from the Solar generation to be used for meeting peak demand.

Q. DOES THE 2020 IRP INCLUDE INFORMATION CONCERNING THE SPECIFIC TYPES AND CAPACITY OF GENERATION PROPOSED UNDER THE OTHER SIX RESOURCE PLANS?

A. Yes. Each of the other six resource plans assumes a different mix of retirements and generation resources, including utility-owned Solar, PPA solar, PPA-plus-Storage, stand-alone Storage, ICT Frame J units, ICT Aero units, and CC 1-on-1 units. In each case, the specific type and capacity of the proposed additional generation supply resources is specified as the statute requires.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP "INCLUDES AN EVALUATION OF . . . COGENERATION" AVAILABLE TO MEET THE UTILITY'S SERVICE OBLIGATIONS AS THE IRP STATUTE REQUIRES?[8]

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[8] S.C. Code Ann. § 58-37-40(B)(1)(e).

A. As general category, cogeneration facilities are facilities that use a single heat source (generally a gas combustion turbine) for both electric generation and a space conditioning or industrial process heat. Most modern cogeneration facilities use natural gas and fuel oil-fired ICTs for a source of heat and electricity, but using a renewable fuel is possible. Existing cogeneration facilities on the DESC system include industrial cogeneration facilities such as the Columbia Energy Center in Lexington County and the WestRock Facility located in North Charleston. As it was originally configured, the Columbia Energy Center supplied thermal energy to the Eastman Chemical/DAK facility, and the WestRock Energy Facility (formerly Cogen South) supplied thermal energy to the kraft paper mill originally constructed in North Charleston by Westvaco. Cogeneration facilities can also include smaller combined heat and power facilities where waste heat is used by hospitals, universities, military facilities, educational institutions, or other facilities for space heating and related purposes.

Under the Public Utility Regulatory Policies Act of 1978 (“PURPA”), such cogeneration facilities are entitled to “Qualified Facility” or QF status under federal law which gives them the right to require the incumbent utility to purchase their capacity and energy at avoided cost and exempts them from much of the regulatory burden and oversight that applies to other wholesale generators. As a result, QF projects can be developed either in partnership with the incumbent utility or, if the economics are favorable, by the steam user or in partnership with private developers.

As the 2020 IRP indicates, the steam resources modeled in Resource Plan 1 and 2 could be implemented as cogeneration without materially changing the modeling of those resource plans. Any additional costs due to a cogeneration configuration of the gas-fired generation would be borne by the steam user and would not impact the customer cost; therefore it will not impact IRP costs or timing.

DESC is open to partnering with a potential steam user when a specific need for additional generation supply has been identified. But, as previously discussed, DESC does not envision procuring new generation supply resources for a number of years and is not currently in a position to approach potential steam users concerning specific cogeneration partnering opportunities. In the meantime, any entity that wishes to pursue a cogeneration project on its own may do so using their rights under the PURPA.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP PROVIDES "DATA REGARDING THE UTILITY'S CURRENT GENERATION PORTFOLIO, INCLUDING THE AGE, LICENSING STATUS, AND REMAINING ESTIMATED LIFE OF OPERATION FOR EACH FACILITY IN THE

PORTFOLIO DATA REGARDING THE UTILITY'S CURRENT GENERATION PORTFOLIO?"[9]

A. Section II (B)(4)(a) of the 2020 IRP (pp. 31–33) lists each of DESC's existing long-term supply resources and shows the age, licensing status, and remaining useful life for each facility as determined in the Company's currently-approved deprecation study.

Q. HOW ARE THE REMAINING USEFUL LIVES OF THE COMPANY'S GENERATION UNITS DETERMINED?

A. The remaining useful lives of all of the Company's utility assets are determined by depreciation studies, which are prepared by independent engineering consultants retained by the Company and are updated as conditions warrant. The IRP reflects the useful life of each generating unit as determined in the most recent depreciation study, which was presented to the Commission for review in Docket No. 2015-313-E and approved for accounting purposes by Order No. 2015-693. These useful lives will be reflected in the IRP process until a new depreciation study is prepared and approved by the Commission.

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[9] S.C. Code Ann. § 58-37-40(B)(1) (f).

Q. HOW DOES THE 2020 IRP REFLECT "CONSIDERATION OF . . . FACILITY RETIREMENT ASSUMPTIONS" AS THE IRP STATUTE REQUIRES?[10]

A. Three of the eight resource plans (Resource Plans 3, 4, and 8) are specifically premised on the early retirement of one or more existing generation units, specifically Wateree Station, McMeekin Station, Urquhart Unit 3, or Williams Station. Each of these resource plans, and the retirement assumptions they represent, was evaluated using the base, high, and low gas price and low, medium, and high DSM assumptions, as well as cases with or without a $25/ton CO_2 emissions cost. These three resource plans fairly evaluate the costs and sensitivities related to unit retirements and early retirements as the statute requires.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP SHOWS "CONSIDERATION OF . . . SENSITIVITY ANALYSES RELATED TO . . . ENVIRONMENTAL REGULATIONS"?[11]

A. Section II (B)(4)(c) of the 2020 IRP (pp. 34–36) summarizes DESC's assessment of the environmental regulations and associated risks that apply to its generation resources. The environmental risks identified principally concern DESC's coal-fired generation units, which are subject to risk of future costs or

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[10] S.C. Code Ann. § 58-37-40(B)(1)(e)(ii).

[11] S.C. Code Ann. § 58-37-40(B)(1)(e)(iii).

regulations that would restrict their usefulness in serving customer demands. At present, the United States Environment Protection Agency (the "EPA") is revising its Steam Electric Effluent Limitation Guidelines ("ELG"). The revised guidelines are anticipated to require substantial capital expenditures to upgrade wastewater treatment for effluent from flue gas desulfurization systems at Wateree and Williams Stations and may require the elimination of the discharge of ash transport water at Williams Station. The alternative to investing the required capital to comply with these new guidelines will be to set a date for closing these units entirely or to strictly limit their use going forward. DESC has factored a response to these ELG requirements into the scenarios modeled either through additional capital costs or early retirements.

In addition, because coal-fired units emit CO_2 at approximately double the rate of high-efficiency natural gas-fired units, they are particularly vulnerable to CO_2 limitations. Modeling of the eight resource plans presented in this IRP demonstrates the relative sensitivity of the plans to CO_2 emissions costs. Specifically, this modeling shows that Resource Plan 2, which is the lowest cost resource plan for customers under the base assumptions, and assuming no cost is imposed on CO_2 emissions, could lose its least cost status if CO_2 costs are imposed at $25/ton. Resource Plan 8 reflects the early retirement of the Wateree and Williams Stations, as well as the conversion of Cope Station to gas-only status. The modeling presented in the 2020 IRP shows that Resource Plan 8 is the lowest cost resource plan assuming substantial costs are imposed on CO_2 emissions.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP SHOWS "FUEL COST SENSITIVITIES UNDER VARIOUS REASONABLE SCENARIOS"[12]

A. Section II (B)(5)(c)(iv) of the 2020 IRP (p. 42) discusses the base, high, and low price forecast for natural gas over the 15-year IRP planning horizon. The low and base forecasts are based on the actual prices at which natural gas contracts traded on the NYMEX exchange for the years 2020-2022. The base and low price cases then reflect different assumptions for price escalation after 2022. The high price forecast is based on the Energy Information Administration's ("EIA") 2019 Gas Price Forecast, which has been consistently higher than actual natural gas prices in recent years. With the decline of coal use, natural gas will be the primary fuel for thermal generation under each plan modeled and the sensitivities of the eight resource plans have been evaluated against a broad range of potential future gas prices.

Q. PLEASE EXPLAIN HOW DESC'S 2020 IRP PROVIDES "AN ANALYSIS OF THE COST AND RELIABILITY IMPACTS OF ALL REASONABLE

[12] S.C. Code Ann. § 58-37-40(B)(1)(b).

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OPTIONS AVAILABLE TO MEET PROJECTED ENERGY AND CAPACITY NEEDS."[13]

A. The modeling done in the 2020 IRP accounts for the impact of generation reliability on energy and capacity cost under all of the resource plans and DSM/load scenarios modeled. As to capacity, the size and timing of the additional supply resources included in each of the eight resource plans have been set to ensure that DESC meets its reserve capacity policy and has a reasonable likelihood of meeting its obligation to its neighboring utilities under the Virginia-Carolina's ("VACAR") Reserve Sharing Agreement and avoiding generation-related blackouts at times of winter and summer peak and throughout the remaining months of the year. The reserves available to meet peak demands are calculated based on the reliability of each generation resource contained in that resource plan (specifically, the forced outage rates and availability factors for those resources), as well as the intermittency effects of renewable resources. The system's ability to meet the reserve capacity policy is measured in light of the sensitivity of the system to extreme weather, and the need to always have capacity in reserve to meet the VACAR reserve sharing requirements. In this way, the modeling done for each of the eight resource plans shows the costs of meeting customer demands considering the reliability factors associated with each resource contained in the resource plan being modeled.

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[13] S.C. Code Ann. § 58-37-40(B)(1)(h).

Similarly, the modeling of energy costs under each scenario take into account forced outage rates and availability factors for the supply resources included in the resource plan being modeled. The model dispatches existing and anticipated generation resources utilizing these availability factors and forced outage rates to determine fuel costs and other incremental operating costs. As to existing resources, the availability factors and forced outage rates are based on actual system data. As to new technologies, generally available engineering data is used to measure these factors. Ramp rates, start-up costs, and intermittency effects are fully accounted for in that modeling.

Q. DOES DESC'S 2020 IRP MEET THE REQUIREMENTS OF THE IRP STATUTE FOR INFORMATION CONCERNING "SENSITIVITY ANALYSES RELATED TO FUEL COSTS, ADOPTION OF ENERGY EFFICIENCY AND DEMAND RESPONSE MEASURES, AND ENVIRONMENTAL UNCERTAINTIES"?[14]

A. Yes. Sensitivity analyses for each of these plans is provided in Section II (B)(5) of the 2020 IRP. The resource plans were modeled against multiple variables including high, low, and base forecasts for natural gas prices; low, medium, and high assumptions concerning the reductions in energy sales growth from DESC's DSM programs; and assumed CO_2 emission prices of zero dollars and $25/ton. The

[14] S.C. Code Ann. § 58-37-40(B)(1)(e)(iii).

resulting 64 scenarios show that Resource Plan 2 is the low-cost plan under the low, medium, and high DSM cases, assuming the gas price equals the base assumption and the CO_2 price is \$0/ton. Resource Plan 2 is also the low-cost plan under the low gas price where the cost for CO_2 is modeled at \$0/ton.

Where the cost for CO_2 is modeled at \$25/ton, Resource Plan 8 is the low-cost plan under each of the gas price sensitivity and DSM cases. Only in one case, the high gas cost and \$0/ton CO_2 price case, does the modeling produce lower costs for a scenario other than either Resource Plan 2 or Resource Plan 8. Under those assumptions, Resource Plan 7 is the low-cost plan. Resource Plan 7 largely mirrors Resource Plan 2 except that it models the addition of 400 MW of flexible solar PPA generation and 100 MW of battery Storage in 2026 and adjusts assumptions as to natural gas-fired generation additions, accordingly. The levelized cost to customers under Resource Plan 7 is lower than Resource Plan 2 in the high gas cost and \$0/ton CO_2 price case but only by less than 0.3%.

While the IRP statute does not require the identification of a specific resource plan among the eight resource plans presented, the base case assumptions for the 2020 IRP defined the most likely scenario for evaluating supply choices going forward. That scenario is premised on the base case assumptions for gas prices, medium DSM load impacts, and \$0/ton CO_2 emission prices. Under those assumptions, and across the greatest number of other sensitivity analyses, Resource Plan 2 is the low-cost alternative for customers and therefore is the preferred plan.

Resource Plan 2 under the medium DSM and \$0/ton CO_2 cost case is the scenario that DESC will use as a basis for avoided cost calculations until updated. An update of the IRP will be filed in February 2021 and each year thereafter.

Q. HOW DOES DESC'S 2020 IRP MEET THE REQUIREMENTS OF THE IRP STATUTE THAT IT PROVIDE INFORMATION CONCERNING "PROJECTED ENERGY PURCHASED OR PRODUCED BY THE UTILITY FROM A RENEWABLE ENERGY RESOURCE?"[15]

A. Section II (B)(3) of the 2020 IRP (pp. 26–30) provides information concerning clean energy and Section II (B)(5)(vii) (p. 49) specifies the energy projected to be purchased or produced from renewable sources by decade under the eight resource plans considered. Under Resource Plan 8, the amount of renewable energy produced or purchased would nearly triple from 20,429 gigawatt hours ("GWh") in the decade 2020-2029 to 59,510 GWh in the decade 2040-2049. Resource Plan 8 shows a 59% reduction in CO_2 emissions by 2030 compared to 2005.

Resource Plan 2 does not assume any significant additions of renewable resources by DESC or others after 2021. Under this assumption, the amount of renewable generation will increase by only a modest amount, from 19,912 GWh in the decade 2020-2029 to 20,339 GWh in the decade 2040-2049. The other six

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[15] S.C. Code Ann. § 58-37-40(B)(1)(c).

resource plans modeled fall between these two plans in terms of future carbon reductions.

Q. DOES DESC'S 2020 IRP PROVIDE A "SUMMARY OF THE ELECTRICAL TRANSMISSION INVESTMENTS PLANNED BY THE UTILITY" AS REQUIRED BY THE IRP STATUTE?[16]

A. Yes. Section III of the 2020 IRP (pp. 52–56) lists the 32 major transmission projects or upgrades currently identified for DESC's transmission system and the nine joint studies completed with neighboring transmission-operating utilities during the prior year. This section of the 2020 IRP also describes the long-range planning criteria and processes which DESC uses to comply with North American Electric Reliability Council ("NERC") and Federal Energy Regulatory Commission ("FERC") reliability requirements and to ensure that its transmission system can meet the needs of its customers as load grows and as distributed generation is added to DESC's system.

Q. PLEASE EXPLAIN WHAT DESC HAS DONE TO COMPLY WITH THE PROVISIONS OF ORDER NO. 2018-804 CONCERNING AN INDEPENDENT CONSULTANT TO REVIEW DESC'S 2020 IRP.

A. In the settlement agreement with the Solar Business Alliance ("SBA") in the Dominion Energy merger proceeding, DESC agreed to retain an independent

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[16] S.C. Code § 58-37-40(B)(1)(d)

consultant to review its IRP. As the 2020 IRP was being finalized, DESC and SBA exchanged lists of potential consultants. Charles River Associates ("CRA") was on both lists. On April 15, 2020, CRA conducted a joint kickoff with DESC and the SBA where they reviewed the scope and methodology it would use in preparing the evaluation and provided comments to CRA. On June 3, 2020, CRA issued its report. Order No. 2018-804 requires that independent consultant's report to be submitted to the Commission. A copy of that report is attached as Exhibit __ (EHB-2). The report generally supports the methodology and conclusions of DESC's 2020 IRP. It suggests several possible refinements in the planning process, which DESC may implement as appropriate in updating the 2020 IRP in February of 2021.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS CONCERNING DESC'S 2020 IRP.

A. DESC's 2020 IRP presents data and analysis that meets all the requirements of the IRP statute. The IRP considers an array of supply and demand-side resources and shows how they can be expected to perform to meet customer requirements over a range of sensitivities. Each of the eight resource plans represents a distinct approach for using available supply-side technologies and demand-side resources to meet customer demands for energy and capacity. Each represents a distinct approach to balancing consumer affordability, least cost, environmental compliance, power supply reliability, and commodity price risk diversity in light of potentially foreseeable future conditions on DESC's system. Each of the eight resource plans have been tested against a broad range of sensitivity cases covering fuel costs, environmental regulations, and the anticipated impacts of DSM on energy sales and demand resulting in the evaluation of 64 distinct scenarios. Collectively these eight resource plans and 64 scenarios define a broad range of approaches to supplying future customer needs.

The modeling done in support of this 2020 IRP shows that, from the customer affordability and least cost standpoint, Resource Plan 2 is the plan that is most beneficial to customers under current conditions. But Resource Plan 8 would likely be the most resilient in the face of increasing environmental limitations on CO_2 discharges and on coal-fired generation. As discussed above, DESC is not facing any decision points in the near term that will require a choice to be made between the eight resource plans that have been modeled in the 2020 IRP. Accordingly, DESC is presenting all eight resource plans as a range of possible approaches to meeting its customers' future capacity needs and will rely on Resource Plan 2 for avoided cost determinations until a new plan is prepared. DESC is asking the Commission to determine that, as a whole, the eight resource plans reasonably balance the relevant statutory factors and provide a reasonable range of options for future evaluation. Based on such a determination, DESC respectfully requests that the 2020 IRP be approved as submitted.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

2020 Integrated Resource Plan

Dominion Energy South Carolina, Inc.

Revised: May 29, 2020
Filed: February 28, 2020

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Executive Summary

For decades, utilities created Integrated Resource Plans ("IRP") to show when customer demand growth required the addition of new resources. During that time, the load forecast and fuel price were the most influential factors in determining which resource plans had the most cost-effective features to provide a safe and reliable supply.

Historically load growth was well anticipated, and even fuel prices were relatively well-known. Other factors like demand side management, energy efficiency, environmental regulations, and greenhouse gas emissions have increasingly dictated the research of additional options and consideration of those options against different measures.

Over the planning horizon, Dominion Energy South Carolina, Inc. ("DESC" or "Company") expects societal trends toward clean energy to continue. Many customer segments from universities and financial institutions to retail chains have expressed interest in renewable energy solutions. Indeed, many large companies including some of the State's largest employers have publicly committed to 100% renewable energy. Moreover, South Carolina cities including Columbia and Charleston are each developing clean energy initiatives with the goal of decreasing their overall carbon footprint.

Furthermore, DESC intends to utilize more power generated from clean energy sources. This IRP also reflects DESC's commitment to clean energy in the energy efficiency programs offered to customers and in the probable modifications to the Company's electric transmission and distribution grid which will facilitate the growth of clean energy solutions while assuring that energy continues to be provided in a safe, reliable, and affordable manner. Aside from the expanding interest in clean energy, renewable resources continue to become a more cost-effective means of meeting the growing energy needs of customers. For example, the continuing development of solar photovoltaic technology has made this type of generation more cost-competitive with traditional forms of generation. Currently, this type of generation does not meet all of the needs of a highly dynamic and critical infrastructure system like the electric grid. It will take innovation and research to find a cost-effective combination of generation, transmission, and distribution to provide reliable clean energy for the future.

In addition to these rapidly increasing influences, the South Carolina General Assembly has enacted new requirements beginning with the 2020 IRP that have impacted its content and scope. Some topics not directly relevant to the required content were not carried over from previous IRPs. Instead, the content is highly focused on information needed to understand and interpret the range of model inputs and sensitivities, and ultimately, the comparison of results shown in the Resource Plan Analysis section.

The newly enacted Act No. 62 as codified at S.C. Code Ann. § 58-37-40(B)(1) establishes mandatory content of IRPs as detailed in the table on Page 4 in the Introduction section. Topics and requirements include sensitivities on the load forecast, generation technologies, renewable resources, electric transmission plans, demand side management ("DSM"), generator retirements, fuel costs, and environmental regulations. As directed, multiple resources plans have been created to provide reliability while including a mix of retirements, new generation technologies, and the expansion of renewables. Several sensitivities are modeled by varying the inputs so relevant comparisons can be made. These sensitivities include CO_2 costs, natural gas/commodity pricing, and customer usage/demand.

Part I explains the considerations and analysis that have resulted in the load forecast including consideration of the relatively new electric vehicle ("EV") market in South Carolina. The Charleston Metropolitan area is poised for EV growth. The overall demographics, the DESC partnership with the Charleston Area Regional Transportation Authority and plans by other private entities to add larger more robust charging stations are helping EV growth in the strongest market. The Company anticipates that the strong growth in Charleston will continue to gain strength. The Company is also seeing strong interest for EV charging along major transportation corridors. Similar adoption rates are expected to follow in markets such as Columbia, Hilton Head and Aiken. The increased local energy demand will certainly require adaptation, initially in all urban areas, and later in rural areas. Urban distribution systems will need additional support from automation and hardening investment in the next few years. DESC will continue to evaluate the EV markets and infrastructure and their potential impact on load. The Company is considering the impact of privately-owned cars and trucks, transit buses, school buses, off road vehicles and commercial fleet vehicles. The demand and energy impact from EV charging is expected to impact grid-level planning in this decade, and the IRP will be adjusted as the EV forecast matures.

Although a preferred scenario is not named in the Resource Plan Analysis, focusing on the most likely inputs identifies Resource Plan 2 ("RP2") that features combustion turbines to maintain the Reserve Margin as the least cost. Resource Plan 8 ("RP8") that features the retirement of all coal generation by 2030 shows modestly higher costs but yields the greatest

CO_2 reductions. These results show a path to CO_2 reductions and associated costs. RP8 could result in a 59% CO_2 reduction by 2030 from 2005 levels verses only a 39% reduction in RP2.

DESC concludes that no major changes to the generation fleet are required in the near term to meet customer's energy and capacity needs in a safe, affordable and reliable manner. However, with a commitment to a more sustainable energy future, the Company needs to upgrade its electric system through measures such as rolling out Advanced Metering Infrastructure ("AMI"), converting some of its older peaking generation to more reliable and quick- start peaking generation, continuing to expand DSM, and studying transmission system to minimize the impact of eventual steam unit retirements and additional intermittent renewable generation.

Introduction

This document presents DESC's IRP which includes several resource plans for meeting the energy and capacity needs of its customers over the next fifteen years, 2020 through 2034. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (2019) and Order No. 98-502 and satisfies the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (2015). The objective of the Company's IRP is to develop a resource plan that will provide safe, reliable cost-effective energy to the Company's customers while complying with all laws and regulations. Given the dynamic nature of the current electric power industry with respect to societal trends, customer preferences, technological advances, and environmental regulations, it is important that Company remain flexible with respect to expansion plans. As such, the resource plans identified in this 2020 IRP present several plausible paths the Company may or may not elect to pursue. What's most imperative is that the Company remain agile regarding expansion of its electric generation portfolio. Therefore, at this time, the Company recommends following a short-term plan consistent with RP2 (and other grid modifications identified in the Conclusions section of this IRP). Simultaneously, the Company shall continue to study and reasonably develop the alternatives put forth in RP8.

DESC's IRP is organized into four parts:

Part I presents the expected loads and peaks on the DESC system over the next fifteen years. Winter peak load forecasted annual growth fell from 0.9% in DESC's 2019 IRP to 0.7% in the 2020 IRP. Many factors were considered in the load forecast including historical sales data, economic factors impacting the Company's commercial and residential customers, DSM which includes energy efficiency ("EE") and load management, and EVs. Low and high demand growth estimates were also derived as required under §58-37-40(B)(1)(a) of Act No. 62 to validate the reasonableness of the final load forecast.

Part II discusses DESC's programs for meeting its demand and energy forecasts, beginning with existing demand and supply-side resources. Highlights include both current expanded DSM programs that will be proposed to customers over the next five years beginning in 2020 since the Potential Study was completed and approved in 2019. The resulting report "Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan" (the "2019 Potential Study") was approved by the Public Service Commission of

South Carolina in December 2019 pursuant to Commission Order No. 2019-880. From this study, the DSM target increased from a 0.33% reduction in retail sales growth in the 2019 IRP to 0.7% by 2023 in the 2020 IRP. The supply-side resources include the current generation portfolio along with discussions about the extreme age of equipment and its end of useful life. A detailed listing can be found in the Existing Long-term Supply Resource Table which lists life expectancy/retirement date as required in Act No. 62 as codified at SC Code Ann. § 58-37-40(B)(1)(a). A detailed Resource Plan Analysis was performed to assess generation scenarios that could meet the future needs of DESC's customers. Several resource plans were created by varying retirements, environmental regulations, and additional renewable resources. While the Company makes observations and conclusions as to which resource plan results in the least cost, the results do not reflect any final decision by the Company for its path forward.

Part III summarizes DESC's transmission planning practices and program development for timely modifications to the DESC transmission system to ensure reliable and economical delivery of power. DESC assesses and designs its transmission system to be compliant with the requirements as set forth in the North American Electric Reliability Corporation ("NERC") Reliability Standards. A summary of the electrical transmission investments planned by the DESC are provided based on the latest assessment studies. The transmission expansion plan is continuously reviewed and may change due to changes in key data and assumptions. This summary of projects does not represent a commitment to build.

Conclusions are presented in Part IV.

Appendix A contains the results of five resource plans run by DESC using the DESC PROSYM production model but with inputs specifically defined by intervening third parties. Although the intervenor resource plans utilized many of the same data inputs, no direct comparisons to DESC's resource plans were included in this IRP due to the low resource cost information provided by the third parties, which in DESC's view, results in a low portfolio cost bias and prevents a practical comparison.

Pursuant to the requirements in S.C. Code Ann. § 58-37-40(B), this IRP (1) demonstrates through various scenarios the resource adequacy and capacity to serve the anticipated peak electrical load and its applicable planning reserve margins, (2) identifies the least cost for consumer affordability, (3) is in compliance with applicable state and federal regulations, (4) ensure power supply reliability, (5) minimizes commodity price risks, and (6) offers diversity in its generation supply. The details of the IRP requirements under Act No. 62 are shown in the following table along with a reference to each section of the Company's IRP demonstrating compliance:

Act 62 Requirements

Act No. 62 58-37-40	Requirement	2020 IRP Section
(B)(1)(a)	a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	I.A I.B
(B)(1)(b)	the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	II.B.5.c
(B)(1)(c)	projected energy purchased or produced by the utility from a renewable energy resource;	II.B.3.c
(B)(1)(d)	a summary of the electrical transmission investments planned by the utility;	III
(B)(1)(e)	several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	II.B.5.c II.B.3.d
(B)(1)(f)	data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	II.B.1 II.B.3 II.B.4.a
(B)(1)(g)	plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	II.B.5.c
(B)(1)(h)	an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	II.B.5.c
(B)(1)(i)	a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	I.A II.A.1 II.A.2
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	II.A.2 II.B.2

Table of Abbreviations	
Abbreviation	**Name**
ACE	Affordable Clean Energy
ATW	Ash Transport Water
BAA	Balancing Authority Area
BEV	Battery Electric Vehicles
BSER	Best System of Emissions Reduction
CC	Combined Cycle Power Plant
CO_2	Carbon Dioxide
DER	Distributed Energy Resource
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
GWh	Gigawatt Hour
HVAC	Heating, Ventilation, and Air Conditioning
ICT	Internal Combustion Turbine
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MWh	Megawatt Hour
NEEP	Neighborhood Energy Efficiency Program
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
ORS	Office of Regulatory Staff
PHEV	Plug-in Hybrid Electric Vehicles
PPA	Power Purchase Agreement
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SEPA	Southeastern Power Administration

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2034

A. DESC's Annual Energy Sales and Peak Demand by Season

The following table shows the Company's annual sales and its gross peak demand, i.e., its total internal demand, by season over the next fifteen years.

Annual Energy and Demand Forecast By Season

	Annual Sales GWh	Peak Demands Summer MW	Winter MW
2020	24,003	4,816	4,891
2021	24,091	4,847	4,924
2022	24,029	4,879	4,955
2023	24,097	4,905	4,964
2024	24,092	4,916	4,992
2025	24,163	4,941	5,022
2026	24,252	4,967	5,051
2027	24,334	4,993	5,077
2028	24,404	5,019	5,102
2029	24,490	5,041	5,152
2030	24,682	5,090	5,209
2031	24,882	5,146	5,266
2032	25,131	5,201	5,319
2033	25,365	5,256	5,375
2034	25,587	5,309	5,428

Note: winter season follows summer.

Over this planning horizon, the Company is projecting through its statistical and econometric forecasting models that sales will grow at 0.5% while the summer and winter peak demands both grow at 0.7%. The following two tables show the Company's projected demand response capacity and the resulting net firm peak demand, i.e., net internal demand, by season. The net firm peak demand in summer and winter are projected to grow at 0.7%.

Net Firm Peak Hour Demand by Year					
Demand Response			Net Firm Peak		
	Peak Demands			Peak Demands	
Year	Summer MW	Winter MW	Year	Summer MW	Winter MW
2020	227	224.4	2020	4,589	4,667
2021	228	225.9	2021	4,619	4,698
2022	229	227.7	2022	4,650	4,727
2023	230	230.2	2023	4,675	4,733
2024	231	234.0	2024	4,685	4,758
2025	232	239.4	2025	4,709	4,782
2026	233	248.9	2026	4,734	4,802
2027	234	261.1	2027	4,759	4,815
2028	235	275.4	2028	4,784	4,826
2029	236	276.4	2029	4,805	4,875
2030	237	277.4	2030	4,853	4,931
2031	238	278.4	2031	4,908	4,987
2032	239	279.4	2032	4,962	5,039
2033	240	280.4	2033	5,016	5,094
2034	241	281.4	2034	5,068	5,146

B. Economic Scenario Analysis

The Company analyzed the sensitivity of its sales growth rate as required by § 58-37-40(B)(1)(a) under Act No. 62. The forecasted growth rate in sales over the 15-year IRP planning horizon of 2020-2034 is 0.5%. To develop a low growth scenario, DESC analyzed the first time it experienced a 15-year negative growth rate which was in 2019 with a compounded annual growth rate of (0.1) %. During this period 2004-2019, DESC lost several wholesale customers. When the growth rate is adjusted for this unusual loss, the growth rate increases to 0%. Given that the State of South Carolina has experienced strong economic growth in recent years, a growth rate of 0% over the long term is highly unlikely. Therefore, the average of this 0% and the base case growth rate of 0.5% was used in the low growth scenario. The low growth rate then is 0.25%. For the high growth scenario, DESC analyzed its growth rate experience prior to the Great Recession which occurred from December 2007 through June 2009. The 15-year growth rates experienced by the Company during this period included a high of 3.4% and a low of 2.7% occurring just prior to the recession, i.e., over the period 1992-2007. When analyzing the detail behind the 2.7% growth rate, the residential and commercial customer growth rates were unusually high, due in part to the housing bubble leading to the recession. Also, the growth in wholesale sales was unreasonable as a proxy for the future because of changes in that class. When the 2.7% was adjusted for these components, the growth rate dropped to 1.7% and was selected as the high growth rate for this scenario analysis. While it is certainly true that DESC's sales could grow less than the low rate of 0.25% or more than the high rate of 1.7%, these rates represent reasonable ranges for the sales forecast. The changes in sales and peak demands from the base case are shown in the following table.

Annual Energy Forecast and Seasonal Peak Demand Change from Base Forecast for High and Low DSM

High Scenario: Change from Base				Low Scenario: Change from Base			
Year	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW	Year	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW
2020	0.0	0.0	0.0	2020	0.0	0.0	0.0
2021	297.9	59.9	60.9	2021	-49.8	-10.0	-10.2
2022	598.0	121.4	123.3	2022	-99.2	-20.1	-20.5
2023	905.1	184.2	186.4	2023	-149.1	-30.4	-30.7
2024	1214.1	247.7	251.6	2024	-198.6	-40.5	-41.1
2025	1531.5	313.2	318.3	2025	-248.7	-50.9	-51.7
2026	1856.1	380.1	386.5	2026	-299.2	-61.3	-62.3
2027	2186.3	448.6	456.1	2027	-349.9	-71.8	-73.0
2028	2521.5	518.6	527.1	2028	-400.7	-82.4	-83.8
2029	2864.6	589.7	602.6	2029	-451.9	-93.0	-95.1
2030	3227.9	665.7	681.2	2030	-505.5	-104.2	-106.7
2031	3602.1	745.0	762.3	2031	-560.0	-115.8	-118.5
2032	3993.9	826.6	845.3	2032	-616.3	-127.6	-130.4
2033	4394.6	910.6	931.2	2033	-673.2	-139.5	-142.7
2034	4804.4	996.9	1019.1	2034	-730.6	-151.6	-155.0

C. Wholesale Sales Scenario Analysis

Wholesale energy sales represent about 3.6% of the Company's total sales. Wholesale customers are served by the Company through negotiated long-term power supply contracts. For periods of time beyond the terms of the existing long-term power supply contracts, the Company has to compete with other power suppliers for the wholesale customers' business. The

Company plans to successfully renew these contracts with current customers and has included the load in its forecast. The table below shows the level of sales and peak demand attributed in its forecasting process to the Company's wholesale business in its base forecast.

Wholesale Portion of Base Forecast

Year	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW
2020	871.0	148	147
2021	871.0	148	147
2022	873.0	149	147
2023	876.3	149	148
2024	879.6	150	148
2025	882.9	151	149
2026	886.3	151	150
2027	889.8	152	150
2028	893.3	153	151
2029	896.8	154	152
2030	900.3	154	152
2031	903.9	155	153
2032	908.0	156	154
2033	912.1	157	155
2034	916.2	157	156

D. Electric Vehicle Scenario Analysis

Electric vehicles have become more common as technology and customer desires change. Various automotive original equipment manufacturers ("OEMs") have released more EV models for sale to the public in the Company's service territory. While the overall penetration of EVs has been somewhat low, recent registration data from the South Carolina Department of Motor Vehicles ("DMV") demonstrates steady growth with a total of 4,145 electric vehicles registered in the state as of mid-year 2019, compared to 2,652 in mid-year 2018 (50% growth rate). This growth coincided with the availability of the popular Model 3 Tesla for purchase. The Company did not augment its 2020 IRP load forecast to account for additional load from EVs; therefore, it should be considered conservative. The forecast only includes incremental load from EVs that is imbedded in history. The next few years will provide the Company with a better understanding about EVs and their impact on the SC energy markets. Load forecasts included in future Company IRPs will include a specific adjustment to account for EV incremental growth.

Before discussing EV scenarios, it is important to understand that a scenario is not a forecast, and it is not a prediction of the future. A scenario analysis is only a "What if" analysis. The EV market in South Carolina is emerging but the data cannot yet be relied upon to make meaningful predictions. However, the scenario analysis is still worth performing because EV market penetration is not a question of "if" but a question of "when". The Company is still in the process of refining its methods for forecasting incremental electric demand growth resulting from the expected increase of EVs in the marketplace. Below a linear analysis was completed meaning demand for EVs would grow evenly over time; however, EV demand growth could be nonlinear or even exponentially higher.

The following table shows an estimate of the number of registered vehicles in DESC's territory. It assumes 2.1 vehicles per household applied to the DESC's residential customer forecast. A distinction is not made between two types of EVs: battery electric vehicles ("BEV") and plug-in electric vehicles ("PHEV"). PHEVs run on both electricity and gasoline. Three scenarios are defined by an assumed EV market share at the end of the IRP planning period. The three assumed ending market shares are: 1%, 5% and 10%. The table shows the number of EVs in DESC's service area under each scenario.

EVs within DESC by Scenario				
Year	DESC Vehicles	EV Scenarios 2034 Saturation Scenario 1%	5%	10%
2020	1,356,174	1,085	1,085	1,085
2021	1,375,662	1,293	2,256	2,806
2022	1,393,867	1,505	3,457	4,572
2023	1,411,311	1,722	4,686	6,379
2024	1,428,727	1,943	5,944	8,229
2025	1,446,356	2,170	7,232	10,124
2026	1,464,460	4,100	13,180	22,846
2027	1,482,268	6,077	19,269	35,871
2028	1,499,629	8,098	25,494	49,188
2029	1,516,523	10,161	31,847	62,784
2030	1,532,794	12,262	38,320	76,640
2031	1,550,199	13,177	48,444	96,887
2032	1,567,528	14,108	58,782	117,565
2033	1,584,626	15,054	69,327	138,655
2034	1,601,342	16,013	80,067	160,134

An approximation of the amount of electric power these EVs will need can be calculated by assuming two quantities: the number of miles driven each year, i.e., 15,000 miles and the number of miles per kWh required, i.e., 4 miles per kWh. The following table shows the results of these assumptions on energy sales over the IRP planning horizon. Customers on the DESC system require about 25,000 GWh per year so in the early years serving these EV sales will not require an immediate adjustment to the resource plan.

EV Energy Sales in 2034 (GWh)			
	2034 Saturation Scenarios		
Year	1%	5%	10%
2020	4.1	4.1	4.1
2021	4.8	8.5	10.5
2022	5.6	13.0	17.1
2023	6.5	17.6	23.9
2024	7.3	22.3	30.9
2025	8.1	27.1	38.0
2026	15.4	49.4	85.7
2027	22.8	72.3	134.5
2028	30.4	95.6	184.5
2029	38.1	119.4	235.4
2030	46.0	143.7	287.4
2031	49.4	181.7	363.3
2032	52.9	220.4	440.9
2033	56.5	260.0	520.0
2034	60.1	300.3	600.5

To derive a table of on-peak MW demand, the Company made certain assumptions. It is assumed that with Level 1 charging, it takes 10 hours on average to fully charge the vehicle's battery while with Level 2 charging, it takes 3 hours. A Level 1 charger charges at 120 volts while a Level 2 charger charges at 240 volts. While the amperage varies and has been increasing, a reasonable assumption is to assume a maximum charge of 1.4 kW for Level 1 charging and 9.6 kW for Level 2[1]. Of course, the number of hours to charge will vary with the car and the size of its battery and its power acceptance rate. Another assumption is the split between Level 1 and Level 2 charging and the percent of on-peak charging. For the three scenarios of 1%, 5% and 10%, it is assumed that the percent of Level 1 charging is 80%, 50% and 20% respectively and the MW on-peak percentages are 50%, 30% and 20%. It is assumed that with a higher saturation of EVs DESC will design a time of use rate that provides a more significant advantage to off-peak charging. The adjacent table shows the results of these assumptions.

[1] There are Level 3 chargers, which include direct current fast chargers, that can charge at rates between 50 kW and 350 kW and possibly larger.

EV Peak Demand (MW)			
	2034 Saturation Scenarios		
Year	1%	5%	10%
2020	0.6	0.5	0.5
2021	0.8	1.1	1.3
2022	0.9	1.6	2.1
2023	1.0	2.2	3.0
2024	1.2	2.8	3.8
2025	1.3	3.4	4.7
2026	2.4	6.2	10.7
2027	3.6	9.1	16.8
2028	4.8	12.1	23.0
2029	6.1	15.1	29.3
2030	7.3	18.2	35.8
2031	7.9	23.0	45.2
2032	8.4	27.9	54.9
2033	9.0	32.9	64.8
2034	9.6	38.0	74.8

There are four other EV markets to consider: transit buses, school buses, off-road vehicles and commercial fleet vehicles. Charleston Area Regional Transportation Authority has placed 3 Proterra transit buses in service as of January 2020 with 3 more being delivered in January 2021. Each bus will require an estimated 80,000 kwh per year and a peak demand of 125 KW.

DESC expects EVs to have the largest initial impact on distribution systems in urban growth areas. Although much of the DESC service territory is rural, the Charleston Metropolitan area is already seeing EV growth. The overall demographics, DESC's partnership with the Charleston Area Regional Transportation Authority, and plans by private entities to add larger more robust charging stations in the Charleston area and along major transportation corridors in South Carolina are helping EV growth. The Company anticipates the strong growth in urban Charleston will continue to gain strength. This year will be a pivotal year for EV sales with 40 models of plug-in EV's already offered, and 14 newer and more attractive models being introduced for 2020. As battery prices are decreasing and driving down the cost of EVs, they will appeal to broader cross section of South Carolina customers. Like Charleston, adoption rates are expected to increase in markets like Columbia, Hilton Head and Aiken. The local distribution impacts will certainly require additional planning and investments. A single Tesla supercharger charging bay has a maximum rated output of 250 kW (350 kW stand-alone) which is almost 40 times that of a residential water heater. Commonly arranged in eight charging bays, the supercharger station could demand 1 MW of new load in a single location. Urban distribution systems will need automation and hardening in the next few years.

II. DESC's Program for Meeting Its Demand and Energy Forecasts in an Economic and Reliable Manner

A. Demand Side Management

DSM can be broadly defined as the set of actions that can be taken to influence the level and timing of the consumption of energy. There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). Energy Efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort but using less energy input in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

1. Energy Efficiency

DESC's Energy Efficiency programs include the portfolio of Demand Side Management Programs, and Energy Conservation. A description of each follows:

a. **Demand Side Management Programs**: Beginning in 2018, DESC, through independent third-party consultants, conducted a comprehensive potential study and DSM program analysis. By Commission Order No. 2019-880, dated December 20, 2019, the Commission approved the suite of ten modified, expanded and new DSM programs, which was identified by the 2019 Potential Study, for the next five years beginning in 2020. Eight of these programs are an expansion or modification of existing programs, and two are new programs. The program impacts identified in the 2019 Potential Study are also the basis for the Medium DSM case in the Resource Plan Analysis. The portfolio includes seven (7) programs targeting DESC's residential customer classes and three (3) programs targeting commercial and industrial customer classes that have not opted out of the DSM rider. A description of each program follows:

    1. **Residential Home Energy Reports** provides customers with monthly/bi-monthly reports comparing their energy usage to a peer group and providing household information to help identify, analyze and act upon potential energy efficiency measures and behaviors. Participants are solicited via direct-mail and e-mail campaigns under an opt-in approach. Per the results of the 2019 Potential Study, the program will begin the necessary activities to phase down existing participants

in the current opt-in model and then phase in an opt-out program model which will include expanding participation. It is expected that by 2023, the program will have completed the full transition to opt-out.

2. **Residential Home Energy Check-up** provides customers with a visual energy assessment performed by DESC staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple energy conservation measures, such as energy efficient bulbs, water heater wraps and/or pipe insulation. The Home Energy Check-up (Tier 1) is provided at no additional cost to all residential customers who elect to participate. Per the results of the 2019 Potential Study, DESC will begin developing an implementation timeline for a Tier 2 component. Tier 2 will include customer incentives for the installation of energy efficiency measures that aim to increase efficient operation of the house.
3. **Residential EnergyWise Savings Store** incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing deep discounts directly to customers. In 2019, DESC continued to offer lighting incentives via an online store, in addition to providing energy efficiency lighting kits to customers at various business office locations, community events and via direct mail. New to the online store, DESC introduced smart thermostats to provide deeper heating and cooling savings to participants.
4. **Residential Heating & Cooling Program** provides incentives to customers for purchasing and installing high efficiency HVAC equipment in existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing air conditioning and heat pump systems through complete duct replacements, duct insulation and duct sealing. Per the results of the 2019 Potential Study, the program will be adding heat pump water heaters, increasing heating and cooling equipment and duct work improvement rebate amounts to encourage participation. An additional new offering will include a rebate for replacing electric resistant heat with a heat pump.
5. **Neighborhood Energy Efficiency Program** ("NEEP") provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-

to-door sweep approach to reach customers. In 2019, neighborhoods in Walterboro, Holly Hill, Charleston and North Charleston participated in the program. Additionally, the NEEP Program continued offerings to mobile and manufactured homes to include additional measures specific to this housing stock. Per the results of the 2019 Potential Study, NEEP will increase customer participation by increasing the number of neighborhoods, increasing penetration into selected neighborhoods and selecting larger neighborhoods,

6. **Residential Appliance Recycling Program** provides incentives to residential customers for allowing DESC to collect and recycle less efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service. Per the results of the 2019 Potential Study, the program will focus on increasing participation through increased marketing and promotional events.
7. **Residential Multifamily** program will focus on helping customers living in non-single-family dwellings, as well as apartment building owners and managers, overcome the split-incentive and other market barriers to residential energy efficiency. The split incentive barrier exists in rental situations: non-occupant building owners are less inclined to make efficiency upgrades when they do not pay efficiency bills, and renters are less likely to make efficiency upgrades because they do not own their dwelling. The program will achieve this goal by directly installing LEDs and water-saving measures in apartments, and by providing high incentives for building common area measures, such as lighting and HVAC upgrades. Although the Neighborhood Energy Efficiency and Home Energy Check-up programs both include multifamily units, the specific targeting of multifamily properties is a new effort and program for DESC.
8. **EnergyWise for Your Business Program** provides incentives to non-residential customers (who have not opted out of the DSM rider) to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on DESC’s website. Additionally, a custom path provides incentives to commercial and industrial customers based on the calculated efficiency benefits

of their energy efficiency plans or new construction proposals. This program applies to technologies and applications that are more complex and customer specific. All aspects of this program fit within the parameters of retrofits, building tune-ups and new construction projects. Per the 2019 Potential Study, the program will increase customer participation and determine an implementation timeline for offering two new components: Agricultural and Strategic Energy Management.

9. **Small Business Energy Solutions Program** is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting and refrigeration upgrades. The program is available to DESC's small business and small nonprofit customers with an annual energy usage of 350,000 kWh or less, and five or fewer DESC electric accounts. Per the results of the 2019 Potential Study, DESC will increase the incentive levels to reduce the barrier to entry for small business customers.
10. **Municipal LED Lighting** program will offer municipalities in the DESC service territory incentives to replace street lighting with high efficiency LED streetlights. The incentives will allow for a financially neutral option for municipalities to convert while improving performance, providing remote monitoring/outage and better overall customer experience. This is a new program that DESC anticipates will be well received by municipalities.

b. **Energy Conservation:** Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each DESC energy conservation offering:

i. **Energy Saver / Conservation Rate**: Rate 6 (Energy Saver/ Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency.

ii. **Seasonal Rates**: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

2. Load Management Programs

The primary goal of DESC's load management programs is to reduce the need for additional generating capacity. There are four existing load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

a. **Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 27 MW of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by DESC's wholesale customers and is made available to DESC System Controllers through contractual arrangements. DESC has a retail version of its standby generator program in which DESC can call on participants to run their emergency generators. This retail program provides approximately 10 MW of additional capacity when called upon.

b. **Interruptible Load Program:** DESC has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when DESC is short of capacity.

c. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under DESC's real time pricing rate. During peak usage periods throughout the year when capacity availability is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Alternatively, during high capacity availability periods, prices are lower.

d. **Time of Use Rates:** DESC's time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All DESC customers have the option of purchasing electricity under a time of use rate.

e. **Winter Peak Clipping:** An investigation of winter peaking programs was performed as part of the 2019 Potential Study. DESC, through independent third-party consultants, modeled a suite of new direct load control and other measures for residential and commercial customers that would rely on AMI being installed. Within the five-year program planning cycle, none of these new DR programs were found to be cost-effective and thus none were pursued further due to the cost of installing AMI as a DSM program expense. However, the 2019 Potential Study showed that a rollout of AMI system-wide outside of the DSM context would support additional expansion of these DR programs. The study indicated that, with a sufficient saturation of AMI in place, Time of Use and Critical Peak Pricing could be cost effective. In absolute terms, by winter 2029, an additional 43 MW could be achieved. Program plans will be assessed as the installation of AMI meters reaches an appropriate level of saturation and can support cost-effective DR programs.

B. Supply Side Management

1. Existing Sources of Clean Energy

Clean Energy at DESC: Clean energy includes nuclear power, hydro power, some forms of combined heat and power, and renewable energy. Over the planning horizon, DESC expects societal trends toward clean energy to continue. Technological improvements and innovation in areas like renewable natural gas, carbon capture, energy storage, energy efficiency and hydrogen are likely to progress in the future. DESC intends to utilize more power generated from clean energy sources while assuring that electricity continues to be safe, reliable and affordable. DESC will continue to monitor the trends toward clean energy to identify approaches to providing customers a path to clean energy while maintaining the standard of reliability and affordability necessary to fuel South Carolina's modern economy.

Current Generation: DESC utilizes clean energy generated by hydro, nuclear and solar.

a. **Solar Power:** DESC has PPA's with utility scale solar energy providers totaling 641 MW-AC currently in commercial operation in addition to over 95 MW of customer scale solar installations interconnected to its grid. The utility scale supply is expected to grow to 973 MW by December 2020.

b. **Hydro-Power:** DESC owns five hydroelectric generating plants, one of which is a pumped storage facility, that combine for a total of 802 MW of clean capacity in the winter and 794 MW in the summer. The Saluda Hydro plant in Irmo, SC has a generating capacity of 198 MW. Saluda Hydro was put into service in 1930 and in August 2008 DESC filed an application requesting a new fifty-year license with the

Federal Energy Regulatory Commission ("FERC"). The Company is still waiting for the issuance of this new license. In June 2019, DESC filed an application with the FERC requesting a new fifty-year license for the Parr Hydroelectric Project, which consists of the Parr Shoals Development and Fairfield Pumped Storage Development. The current license expires in June 2020. This project is critical for the future of DESC's generation portfolio. With the increased adoption rate of non-dispatchable, intermittent solar generation on the DESC system, Fairfield Pumped Storage is an important asset for grid stability, reliability and power quality for DESC customers. In 2019, DESC's hydroelectric plants produced 288.1 gigawatt-hours ("GWh") of clean energy for SC customers. DESC's pumped storage facility, Fairfield Pumped Storage, has a net dependable generating capacity of 576 MW and is a valuable asset to the DESC generation fleet. Fairfield Pumped Storage contributed 469.5 gigawatt-hours ("GWh") in 2019 and has been a reliable resource for responding to rapid load changes on the DESC system. In 2018, the Company started the process of relicensing the Stevens Creek Hydroelectric Project which expires in October 2025. DESC will file an application with the FERC by October 2023 requesting a new fifty-year license for this project. This project provides fairly constant generation as it re-regulates the releases from the US Army Corps of Engineers J. Strom Thurmond Hydroelectric Project.

c. **Nuclear Power**: Unit 1 at the V. C. Summer Nuclear Station ("VCSNS") produces a substantial amount of clean energy and has a significant beneficial impact on the environment. The Unit came online in January 1984 and has a capacity of 971 MW with DESC owning 650 MW (two-thirds of the output of the facility) and Santee Cooper owning the balance. DESC received a 20-year extension to its original operating license in April 2004 and will enter its period of extended operation in 2022, since it is now licensed to operate until August 2042. Once VCSNS enters its period of extended operation, DESC expects to request and receive approval of a subsequent license renewal, extending its licensed operation to 2062. In 2019, Unit 1 produced over 5,720 gigawatt-hours ("GWh") of clean base load energy, which represented 20% of DESC's energy production. Over these next 22 years Unit 1 should produce approximately 110,000 GWh of clean base load energy for DESC. Nuclear generation currently displaces approximately 3.2 million tons per year of CO_2 that would be emitted if replaced by fossil resources.

2. Distribution Resource Plans

DESC is participating in activities seeking to advance technologies in grid transformation.

Smart Grid Activities:

Advanced Metering Infrastructure: DESC currently has approximately 30,000 AMI meters that are installed predominately on medium and large commercial/industrial customers and all accounts with customer generation (net metering). They are also used for accounts on time-of-use or demand rates. These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Meter readings and load profile interval data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is made available to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. DESC is in the early implementation stage for mass AMI technology for all electric meters with full scale deployment scheduled to begin in 2020. Deployment plans have meter installations ramping from 10,000 meters per month to 35,000 meters per month over the next three years. Depending on customer growth, the final total meter count will be just over 765,000 AMI meters installed in the DESC service territory. This expands the opportunity to field Home Area Network devices that communicate via AMI meters. This project will allow DESC to offer and customers to participate in demand response, demand shifting, and demand shedding programs around load control devices including water heaters, HVAC systems, pool pumps and electric vehicle chargers.

Distribution Automation: DESC is continuing to expand Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. DESC has approximately 1,100 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing outage times and limiting affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. DESC continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar). As distributed renewable generation proliferates in the system, identifying issues such as voltage control and load flows are imperative to maintaining reliability now and for future grid stability planning.

3. Future Clean Energy

a. Hydro-Power: DESC plans to continue to rely on clean dispatchable power from all of the existing hydro and pumped storage units through successful completion of the relicensing processes of Saluda, Parr, and Stevens Creek hydroelectric projects and Fairfield Pumped Storage Facility.

b. CO_2 and Methane Goals: As one of the nation's largest producers and transporters of energy, Dominion Energy is committed to providing safe, reliable, affordable and sustainable delivery of energy to its customers. The Dominion Energy expects to cut the electric generating fleet’s carbon dioxide emissions 55 percent by 2030 relative to 2005 emissions and reduce methane emissions from its gas assets 65 percent by 2030, 80 percent by 2040, both relative to 2010 emission levels. Dominion Energy has further committed to achieve net zero CO_2 and methane emissions from its electric generation and natural gas infrastructure operations by 2050. To the extent possible, subject to South Carolina stakeholder processes, DESC plans to participate in efforts to meet these corporate commitments.

c. **Renewables:** The following table provides a projection of renewable generation from signed PPAs as used in DESC Resource Plan #2 in the Resource Plan Analysis section.

Resource Plan 2 Renewable Energy by Year (GWh)

Year	GWh
2020	1,609
2021	2,032
2022	2,034
2023	2,034
2024	2,034
2025	2,034
2026	2,030
2027	2,032
2028	2,042
2029	2,032
2030	2,032
2031	2,034
2032	2,036
2033	2,034
2034	2,034

DESC has 973 MW-AC of solar capacity currently under executed PPAs. The preceding table shows the amount of energy projected to be generated by these renewable facilities in each of the 15 years of the IRP planning horizon. Please note, all 973 MW-AC of capacity is expected to be online by January 2021 and the table does not take into consideration solar projects in development without a PPA at this time. Retiring coal-fired generation has the greatest impact on CO_2, and some of that energy can be supplied by additional solar generation. Still, as hundreds and thousands of solar panels are added, significant transmission and distribution upgrades along with a combination of energy storage and quick start combustion turbines will be required on the electric grid due to intermittency.

Photovoltaic solar generation systems are quite different from traditional supply-side resources like coal, nuclear, and natural gas-fired power plants. All levels of the existing electric infrastructure, standards and operating protocols were originally designed for a dispatchable generation fleet, and the system is having to adapt to integrate these new resources. Solar generation systems, in contrast, only produce electricity when the sun is shining; therefore, energy output is variable and cannot be dispatched.

As a NERC registered Balancing Authority, DESC must maintain real time load-interchange-generation balance within its Balancing Authority Area ("BAA") between customer demand and generation (which can include traditional coal, nuclear, gas, and hydro, as well as solar resources and off-system purchases). The criteria within which the Company must operate are defined by multiple NERC Reliability Standards and require the Company to maintain a balance of resources and demand within defined limits. Variability in solar generation can cause sudden swings in this balance and can result in both reliability issues and NERC Standards Violations if operators' actions are insufficient. To counter the swings caused by solar generators, the Company must maintain complementary dispatchable generation online and available to respond to reliability events created by sudden swings in solar generation output.

In particular, downward ramp rates for PV solar generators are nearly instantaneous when cloud cover rolls over panels, so the Company must have compensating supply-side resources online or ready to respond with quick start times and fast ramp rates. For this reason, operating reserves from slow moving coal units are not adequate, making other quick moving resources including pumped storage facilities, batteries and quick start combustion turbines more critical and necessary as intermittent resources are added.

From a supply standpoint, the BAA peak load is approximately 5,000 MW, but loads at this level are only seen a few hours each year. These peak loads occur late in the afternoon on the hottest July and August days, or the coldest early morning hours in January or February just before sunrise. For the Company's 2019 summer peak of 4,714 MWh, PV generation directly connected to the Company's transmission and distribution system contributed 264 MW-AC or 52% of its installed capacity, while for the winter peak of 4,087 MWh to date in 2020 (mild winter), solar generation contributed 9 MW-AC or 1.4% of installed capacity toward meeting the peak. The remainder of load in both scenarios (4,450 MWh in July and 4,078 MWh in January) was balanced with traditional Company generation and off system purchases. At a minimum, these numbers demonstrate that capacity from solar generation is out of sync with peak loads in the winter and only partially in sync in the summer. Therefore, large amounts of energy storage and dispatchable generation must be available to respond to load demand and reliability events on peak days because solar cannot functionally provide that reliability benefit alone.

Quick start, flexible, and reliable combustion turbines are especially critical for capacity and energy supply in the winter. Winter peak demand occurs in the morning and often before sunrise when solar resources are not producing. The issue is further impacted by the fact that in the winter the days are shorter meaning batteries have less charging time. Combustion turbines can cost-effectively meet this peak need when solar plants are producing little or no output. In situations where it is not only cold but also cloudy, as often happens in the winter, combustion turbines provide the energy supply needs of our customers into the day. Another critical energy situation exists when it is cloudy for several days in a row. In this situation, very little solar power is being produced for days. For systems with heavy reliance on solar resources, several cold and cloudy days in a row will be a reliability design issue. A cost-effective strategy must be in place to replace renewable energy during these events. Even batteries paired with solar will not solve the very real and not so distant problem of low solar output for several cloudy days with high demands. Efficient, reliable, combustion turbines are an essential facet of a low carbon future.

DESC anticipates increasing levels of renewable resources along with the research and innovation that will make reliable operations possible. Technical advances must be implemented with regard to cost and reliability and in conjunction with established flexible technologies. The incremental implementation of solar and storage technology with moderate additions over several years will allow the electric grid to adapt to operational impacts in a cost-effective manner.

d. Cogeneration/Combined Heat and Power: The Company is open to combined heat and power that provides clean energy or improved efficiency should a specific project present itself. Combined heat and power projects are highly dependent upon the steam user's individual steam requirements and are therefore impossible to accurately model as a generic project. The Company is open to customer-sited generation opportunities; this includes siting generation assets to supply critical infrastructure during system emergencies including (but not limited to): military installations, hospitals, universities, and major government facilities. Such distributed generation assets can also be used for operation during system peak periods. Both Resource Plan 1 ("RP1") and RP2 could be configured to be a cogeneration plan to utilize the waste heat produced.

e. Energy Storage: Energy storage is critical to providing continued reliability for our customers as we expand our renewable portfolio. There are several types of energy storage technologies including pump storage, capacitors, compressed air, flywheels and batteries. Except for pump storage and batteries, most of these technologies are not yet cost competitive. Pump storage requires specific land features and lengthy permitting; therefore, this IRP focuses on batteries in conjunction with its existing Fairfield Pump Storage Facility.

The Company continues to evaluate storage as an option to manage minimum loads and integrate increasing levels of renewables onto the system. Because solar generates when the sun is shining and doesn't generate when the sun is not shining, its generation does not always correspond with the system's need for generation. Energy storage can enable the utility to shift solar energy from periods when it's not needed. These minimum and maximum load issues are most visible in the winter. The winter peak occurs in the early morning before the sun comes up. After the sun comes up, in the winter, the load begins to drop as temperatures begin to rise. Solar generation increases as the load drops. This is an example of a minimum load issue that could be resolved by storing solar energy. This stored solar energy can be used to help meet maximum loads during a later period when solar is not generating. Battery storage has made significant strides in recent years, in both efficiency and cost but it is still in the early stages of utility-scaled deployment.

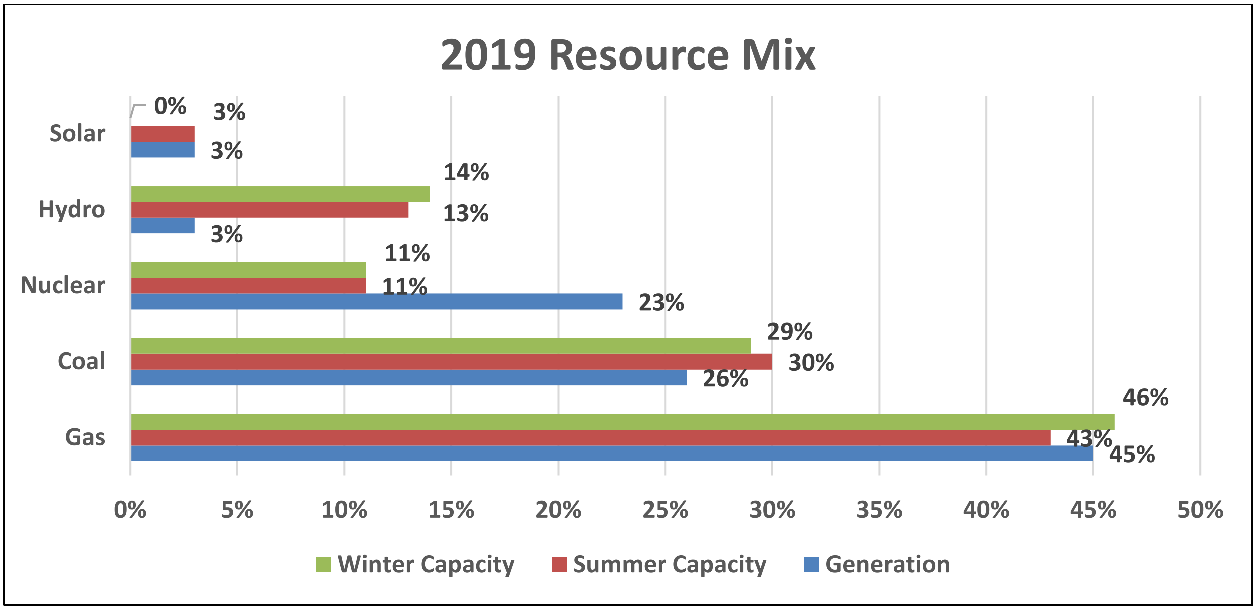
4. Supply Side Resources at DESC

a. **Existing Supply Resources:** DESC currently owns and operates two (2) coal-fired steam plants, one (1) dual-fuel coal and/or natural gas-fired steam plant, two (2) natural gas-fired steam plants, three (3) combined cycle gas turbine/steam generator plants (gas/oil fired), seven (7) peaking turbine facilities, four (4) hydroelectric generating plants, and one pumped storage facility. The total fossil-hydro generating capability rating of these facilities is 5,001 MW in summer and 5,248 MW in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When DESC includes its nuclear capacity (650 MW in summer and 662 MW in winter), additional capacity (20 MW) provided through a contract with the Southeastern Power Administration and solar capacity, the total supply capacity for 2020 is 6,507 MW in summer and 6,905 MW in winter. This is summarized in the table on Page 33.

Solar only contributes a portion of its capacity toward the summer peak and virtually none of its capacity toward the winter peak. This difference is because the solar profile and DESC's load profile are not congruent. Summer peaks happen in the afternoon after solar generation has begun to decline and winter peaks happen in early mornings before solar begins to generate. The Company continues to assess combining solar technology with batteries and other storage technology to optimize the amount of solar generation that can efficiently serve the Company's peak load demand.

The bar chart below shows DESC's actual 2019 relative energy generation and relative capacity by fuel source. This information includes the summer and winter capacity contribution of Solar PPAs which was 3% of summer capacity and 0% of winter capacity.

DESC 2019 Resource Relative Production



The purpose of this chart is to emphasize the resources that have provided the highest capacity contribution on peak and the most energy supply over a year. Hydro resources provided disproportionately higher capacity value while the nuclear plant contributed well to capacity and extremely well for energy supply. Thermal resources continued to contribute significantly to both energy and capacity needs. Without storage capability, the solar contribution to on peak capacity is low.

Existing Long-Term Supply Resources

The following table shows the DESC available generating capacity in 2020.

	In-Service Date	Probable Retirement[1] Date	Summer 2020 (MW)	Winter 2020 (MW)
Coal-Fired Steam:				
Wateree – Eastover, SC	1970	2044	684	684
Williams – Goose Creek, SC[2]	1973	2047	605	610
Cope[4] - Cope, SC	1996	2071	415	415
Total Coal-Fired Steam Capacity			1,704	1,709
Gas-Fired Steam:				
McMeekin – Irmo, SC	1958	2028	250	250
Urquhart – Beech Island, SC	1954	2028	95	96
Total Gas-Fired Steam Capacity			345	346
Nuclear:				
V. C. Summer - Parr, SC	1982	2062	650	662
Gas Turbines:				
Hardeeville, SC	1968	2018	0	0
Urquhart 1,2,3 – Beech Island, SC	1969	2044	39	48
Urquhart 4 – Beech Island, SC	1999	2059	48	49
Coit – Columbia, SC	1969	2029	26	36
Parr, SC	1970	2030	60	73
Williams – Goose Creek, SC	1997	2057	40	52
Hagood 4 – Charleston, SC	1991	2051	88	99
Hagood 5 – Charleston, SC	2010	2070	18	21
Hagood 6 – Charleston, SC	2010	2070	20	21
Urquhart Combined Cycle – Beech Island, SC	2002	2077	458	484
Jasper Combined Cycle – Jasper, SC	2004	2079	852	924
CEC Combined Cycle – Columbia, SC	2004	2079	519	586
Total I.C. Turbines Capacity			2,168	2,393
Hydro:				
Neal Shoals – Carlisle, SC	1905	2055	3	4
Parr Shoals – Parr, SC	1914	2064	7	12
Stevens Creek - Near Martinez, GA	1929	2079	8	10
Saluda - Irmo, SC	1932	2082	198	198
Fairfield Pumped Storage - Parr, SC	1978	2128	576	576
Total Hydro Capacity			792	800
Solar:[3]				
Company Owned	2011	2031	2.4	2.4
PPA DER Program	2015-2019	2039	64	64
PPA Non-DER Program,	2017-2020	2040	762	909
Total Solar Capacity			828	975
Other:				
Southeastern Power Administration (SEPA)			20	20
Grand Total (Name Plate):			6,507	6,905
				-

Notes:
1. Probable retirement dates are based on the 2014 Depreciation Study.
2. Williams Station is owned by South Carolina Generation Company ("GENCO"), a wholly-owned subsidiary of SCANA Corporation which is a wholly-owned subsidiary of Dominion Energy, Inc. and GENCO's electricity is sold exclusively to DESC.
3. Solar MW are nameplate values and do not represent the contribution to peak demand.
4. Cope Station is dual fuel and is run on both coal and natural gas.

b. Limitations on Existing Resources: DESC is evaluating the possible replacement of existing peaking generation assets as intermittent renewable resources continue to expand in the service territory and several combustion turbines reach end of life. DESC's existing fleet of simple-cycle combustion turbines is on average over 42 years old, with multiple units at or approaching over 50 years since initial commercial operation. DESC's natural gas-fired steam units (McMeekin Units 1 and 2 and Urquhart Unit 3) also typically operate as peaking resources, and these units are over 60 years old. Reliable, fast-starting, and efficient peaking resources provide significant capabilities to balance intermittent renewable generation. Replacement of DESC's aging peaking generation resources with flexible aeroderivative-type combustion turbines is seen as a likely potential path to provide the flexibility to allow for further integration and additional expansion of intermittent renewable resources in the near-term. As discussed above in the Introduction, DESC expects trends toward clean energy to continue. Further, the Company is committed to utilizing more power generated from clean energy sources. As such, the Company will continue in future IRPs to explore generation, transmission, and distribution technologies necessary to achieve this clean energy goal.

This IRP contains references to retiring generators. DESC Transmission Planning must conduct System Impact Studies to determine the impacts of any planned generator interconnection, retirement, or replacement requests. DESC Transmission Planning studies these requests to determine the reliability impact to the DESC Bulk Electric System. Those studies determine what transmission system upgrades are necessary to support the associated generator requests and are performed independently from DESC's Power Generation and DESC Retail Electric organizations.

c. Environmental Rules: DESC continues to closely monitor developments with the US Environmental Protection Agency's ("EPA") Steam Electric Effluent Limitation Guidelines ("ELG") following the Agency's actions after the 2015 final rule was published. This regulation is anticipated to require significant capital expenditures for flue gas desulphurization ("FGD") wastewater treatment at both Wateree and Williams Stations and for modifications to limit or eliminate the discharge of ash transport water at Williams Station. Recent fuel price trends along with increased intermittent renewable generation have resulted in cyclic operation of these facilities along with reduced capacity factors. These conditions make FGD wastewater treatment retrofits challenging and costly.

In November 2019, EPA issued a proposed rule to revise the 2015 standards. In the 2019 proposed rulemaking, EPA proposed significant changes to the rule including new effluent limits and an incentive for early retirement of existing generating units. DESC will continue to closely monitor the EPA's rulemaking in anticipation of a final ELG regulation in 2020. Along with the additional costs of stack emission reductions and the ELG Rule, traditional coal-fired steam boiler generating units emit CO_2 at twice the rate of the highest efficiency natural gas fired combined cycle unit due to fuel carbon content and efficiency. For immediate reductions in CO_2 emissions, coal-fired units must be operated less frequently by reducing demand, operating more natural gas-fired generation, and adding solar generation with batteries along with combustion turbines for back up and load following.

EPA released the final version of the Affordable Clean Energy ("ACE") rule, the replacement for the Clean Power Plan ("CPP") on June 19, 2019. The rule was published on July 8, 2019 and applies to existing coal-fired power plants greater than or equal to 25 MW. Through the ACE rule, the EPA finalized the repeal of the CPP. It is also asserted that the repeal is intended to be severable, such that it will survive even if the remainder of the ACE rule is invalidated.

Under the ACE rule, EPA has set the Best System of Emissions Reduction ("BSER") for existing coal-fired steam electric generating units as heat rate efficiency improvements ("HRI") based on a range of "candidate technologies" and improved operating and maintenance practices that can be applied at the unit level. States are directed to determine which of the candidate technologies apply to each unit and establish standards of performance (expressed as an emissions rate in CO_2 lb/MWh) based on the degree of emission reduction achievable with the application of BSER. EPA requires that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors such as reasonable cost of the candidate technologies.

The rule requires compliance at the unit level; it does not allow averaging across units at the same facility or between facilities as a compliance option. In addition, it does not allow states to use alternative carbon mitigation programs, such as a cap-and-trade program, to demonstrate compliance as part of their state plans. A steam generating unit that is subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less can be excluded from the ACE rule. The ACE rule requires states to develop plans by July 2022. These state plans must be approved by the EPA by January 2024. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

5. Resource Plan Analysis

a. Overview

The following pages document a resource planning study that was performed to assess several resource plans to meet customers' need for power while varying future market conditions and regulations. Included in the Company's study were eight resource plans and three sets of DSM scenarios. The eight plans were also evaluated under three levels of natural gas prices and two CO_2 emission cost prices. The Company's base forecast of energy and demands was used in the study. The Load Forecast (discussed in Part I) is called the Medium DSM case. Medium DSM is based on the expected program levels identified in the 2019 Potential Study and are the programs the Company plans to deploy. By modifying the Load Forecast with other levels of DSM, Low and High DSM sensitivities are included in the Resource Plan Analysis. The existing DSM level is called Low DSM. The 2019 Potential Study level is called Medium DSM, and a 1.0% level of DSM is called the High DSM case. The DSM Low and Medium cases were studied for cost-effectiveness and provide a reliable cost estimate that is unique to the portfolio of programs and customers in DESC's electric system. The High DSM case was not supported in the 2019 Potential Study and is based on estimates.

Resource plans were created around retirements, environmental regulations and additional renewable resources. These scenarios create a large array of output data. The following pages include several displays of the high-level output data meant to emphasize the most relevant results. Understanding the common basis of each resource plan and limited changes between resource plans provide for relevant comparisons. Comparing resource plans created with dissimilar assumptions will yield inappropriate conclusions, and care must be taken to understand the inputs that are held constant versus inputs that have changed to avoid such pitfalls.

b. Reserve Margin

DESC's reserve margin policy is summarized in the following table. Peaking reserves are considered the capacity needed during the five highest peak load days in the season while base reserves are needed for the balance of the season.

DESC's Reserve Margin Policy		
	Summer	**Winter**
Base Reserves	**12%**	**14%**
Peaking Reserves	**14%**	**21%**
Increment for Peaking	**2%**	**7%**

Statements about reserve margin are generally addressing Base Reserve criteria.

c. Meeting the Base Resource Need

In the context of base or peaking, base resources are the resources explicitly identified in a resource plan's 40-year schedule to meet the summer or winter base reserve margin. Peaking reserve margin assists in quantifying reliability risk but is not used for deciding on permanent capacity resources. For base resources the winter base reserve margin of 14% was used to determine the timing of adding generation resources. DESC created a list of seven generating resources to be considered. The following table lists these resources. Wateree and Williams are assumed retired when they reach their end of life, which is years 2044 and 2047 respectively, if not retired earlier. The capital costs are escalated or de-escalated from 2020 to the year that the generator is installed. The installation year varies by resource plan. The capacity used in the resource plan schedule for CC and ICT resources is their winter capacity.

Description of Potential Resources

Resource	Capital Cost 2020 $/kW	Escalation Rate	Capacity	Source of Data
Battery Storage	$1,911	-2.463%	100 MW with 4 hour duration	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from NREL Mid Technology Cost Scenario forecast of CAPEX, 30 Year Average
Solar	$1,151	-1.498%	100 or 400 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from NREL Mid Technology Cost Scenario forecast of CAPEX, 30 Year Average
CC 1-on-1	$1,330	3.75%	553 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Frame J (2x)	$469	3.75%	523 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Aero (2x)	$918	3.75%	131 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
Solar PPA	N/A	N/A	400 MW	• NREL 2019, Mid Technology Cost Scenario

i. Resource Plans

These six resources above were combined in various ways to develop eight resource plans, some of which consider the retirement of some existing generating units. The eight resource plans are listed in the following table which is followed by a description of each resource plan.

Description of Resource Plans

Resource Plan ID	Resource Plan Name	Resource Plan Description
RP1	CC	Combined Cycle, ICTs
RP2	ICT	ICTs
RP3	Retire Wateree	Wateree 1 & 2 retirement, Combined Cycle, ICTs
RP4	Retire McMeekin	McMeekin and Urquhart 3 retirement, ICTs
RP5	Solar + Storage	Flexible Solar + Battery Storage, Combined Cycle, ICTs
RP6	Solar	Flexible Solar, ICTs
RP7	Solar PPA + Storage	Flexible Solar PPA + Battery Storage, ICTs
RP8	Retire Coal	Replace Wateree and Williams with Combined Cycle, Solar and Battery Storage, ICTs

Flexible solar is a solar facility which can be curtailed when systems conditions require and/or dispatched with system needs

Resource Plan 1: In this resource plan a 553 MW (winter capacity) combined cycle gas generator is added when the winter reserve margin drops below 14%. 523 MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 2: In this resource plan 523 MW (winter capacity) of ICT gas generators are added when the winter reserve margin drops below 14% during the modeling period.

Resource Plan 3: In this resource plan Wateree units 1 and 2 are retired in 2028 and a combined cycle gas generator is added in 2028. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 4: In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2028. Their 346 MW of capacity are replaced by 523 MW of ICT capacity. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 5: In this resource plan 400 MW of Company owned flexible solar generation plus 100 MW of battery storage are added in 2026. The next increment of capacity necessary to maintain a 14% winter reserve margin is a 553 MW combined cycle gas generator. After the CC, 523 MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 6: In this resource plan 400 MW of Company owned flexible solar generation is added in 2026. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 7: In this resource plan 400 MW of flexible solar PPA generation plus 100 MW of battery storage are added in 2026. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 8: In this resource plan Wateree and Williams are retired in 2028 and replaced with a 553 MW 1-on-1 combined cycle plant and Five hundred twenty-three (523) MW of ICTs. Dual fuel capability is eliminated at Cope, so Cope burns only natural gas starting in 2030. Additional tranches of 100 MW of battery storage and 131 MW ICTs are added to maintain the 14% winter reserve margin during the modeling period. Solar is added each year from 2029 to 2048. This resource plan is the low carbon plan.

ii. Methodology

The incremental revenue requirements associated with each of the eight resource plans was computed using the PROSYM computer program to estimate production costs and an EXCEL revenue requirements model to calculate the associated capital costs. The EXCEL revenue requirements model combines the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon.

iii. Demand Side Management Assumptions

Three DSM cases were created. The low DSM is equivalent to DSM programs and levels on the DESC electric system prior to the 2019 Potential Study. The medium DSM used the results of the 2019 Potential Study described in Part II.A. High DSM assumed DSM Growth to 1% of retail sales by 2024. It should be noted that the High DSM case was not supported in the 2019 Potential Study and is based only on estimates, likely not achievable and cost effectiveness is unknown.

The three DSM cases created three demand and energy forecasts. A low level of DSM creates higher demands and energy. A high level of DSM creates demands and energies that are lower. The cost for each DSM case was calculated over a 40-year period and applied to the appropriate scenario. Assuming no baseload retirements, the first need for additional capacity occurs in the winter of 2035 when using the Medium DSM demands, in 2032 when using the Low DSM demands and 2038 when using the High DSM demands.

iv. DSM Sensitivity

The following tables summarizes the results for all eight resource plans under the three different DSM cases. (1 – Green = Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan Rankings by Levelized NPV for Low, Medium and High DSM

Resource Plan ID	Resource Plan Name	Low DSM	Medium DSM	High DSM
RP1	CC	6	5	4
RP2	ICT	1	1	1
RP3	Retire Wateree	2	6	6
RP4	Retire McMeekin	5	3	5
RP5	Solar + Storage	8	7	8
RP6	Solar	4	4	2
RP7	Solar PPA + Storage	3	2	3
RP8	Retire Coal	7	8	7

Resource Plan Levelized NPV for Low, Medium and High DSM ($000)

Resource Plan ID	Resource Plan Name	Low DSM	Medium DSM	High DSM
RP1	CC	1,254,935	1,249,160	1,244,419
RP2	ICT	1,231,227	1,231,667	1,228,438
RP3	Retire Wateree	1,242,386	1,251,077	1,249,280
RP4	Retire McMeekin	1,248,340	1,239,802	1,248,403
RP5	Solar + Storage	1,272,513	1,266,727	1,264,403
RP6	Solar	1,244,428	1,246,165	1,243,761
RP7	Solar PPA + Storage	1,242,682	1,236,518	1,243,916
RP8	Retire Coal	1,271,348	1,267,624	1,260,246

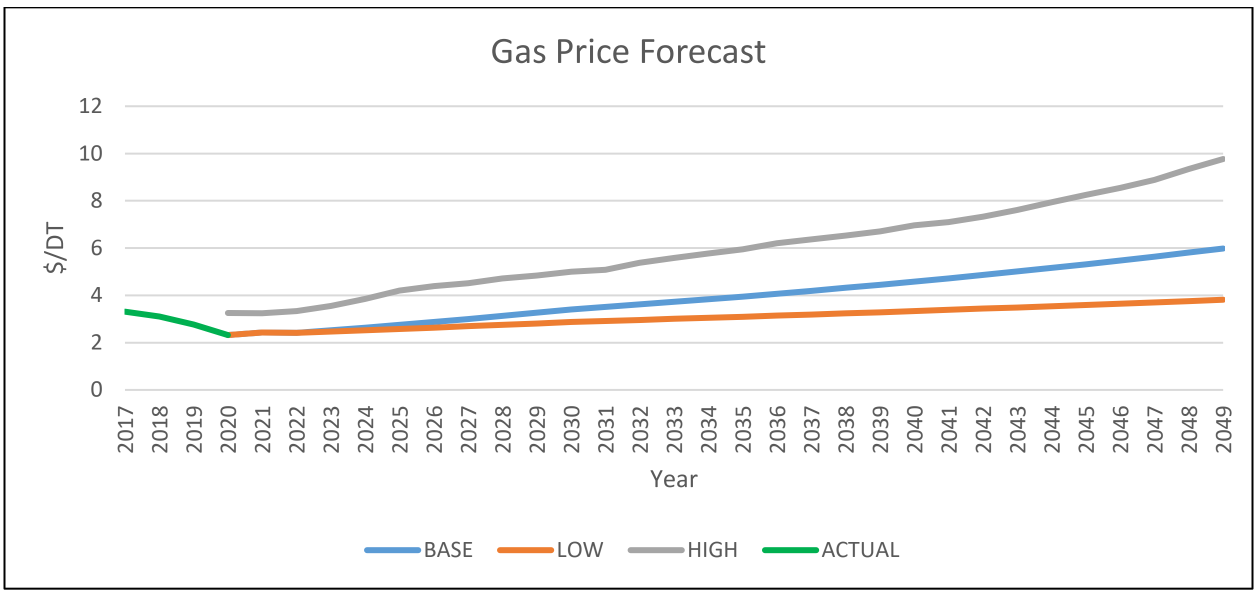
v. Discussion of Results by DSM scenario:

RP2 is the lowest cost resource plan under the assumption of zero cost CO_2 and base gas prices for all levels of DSM modeled. This is driven by the low cost of building two 260 MW ICTs simultaneously several years into planning time frame. Costs in the short-term would have a greater impact on Net Present Value calculations. Since the reserve margin calculation is not a constraining factor until after 2030, the resource plans generally do not show large changes in the first few years. Using RP 2, no resources are added due to reserve margin constraints until 2035 in the Medium DSM case. Due to the timing of the resources, the differences in NPV are separated by about 3% within each level of DSM with the expected scenario. At $0 CO_2 costs and Base Gas Price, RP 2 has the lowest projected cost in each DSM sensitivity. RP 6 – Solar and RP 7 – Solar PPA + Storage also do well in the Medium DSM and High DSM cases.

vi. Emissions and Fuel Sensitivity

The medium DSM case was evaluated using three gas price assumption plus two CO_2 cost assumptions. The combination of the three gas price assumptions and two CO_2 cost assumptions created 6 different scenarios. The chart below shows the three gas price forecasts used. The high gas price forecast is the 2019 EIA gas price forecast. The base gas and low gas scenarios are based on NYMEX gas prices for years 2020-2022 then escalated at two different rates. The base escalation rate is derived from the EIA gas price forecast. The low gas scenario escalation rate is half of the base gas escalation rate. The two CO_2 assumptions used were $0/ton and $25/ton. All plans include assumptions about expenses that will be required to meet ELGs for Wateree and Williams.

Low, Base and High Gas Price Forecast



vii. Resource Plan Rankings by Gas Price and CO_2 Price

The following tables summarizes the 40 year levelized NPV cost results for all eight resource plans under the three different gas price cases and two different CO_2 price cases. (1 - Green= Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan Levelized NPV Rankings for Medium DSM

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	6	5	5	7	6	6
RP2	ICT	1	1	2	3	4	3
RP3	Retire Wateree	5	6	7	4	3	5
RP4	Retire McMeekin	2	3	4	6	7	8
RP5	Solar + Storage	8	7	6	8	8	7
RP6	Solar	4	4	3	5	5	4
RP7	Solar PPA + Storage	3	2	1	2	2	2
RP8	Retire Coal	7	8	8	1	1	1

Resource Plan Levelized NPV for Medium DSM (\$000)

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	\$1,166,528	\$1,249,160	\$1,427,424	\$1,385,375	\$1,469,436	\$1,668,590
RP2	ICT	\$1,145,532	\$1,231,667	\$1,416,354	\$1,370,853	\$1,461,736	\$1,665,599
RP3	Retire Wateree	\$1,165,235	\$1,251,077	\$1,444,505	\$1,372,378	\$1,460,334	\$1,666,688
RP4	Retire McMeekin	\$1,154,191	\$1,239,802	\$1,425,558	\$1,380,307	\$1,470,231	\$1,675,337
RP5	Solar + Storage	\$1,186,034	\$1,266,727	\$1,435,093	\$1,394,516	\$1,475,915	\$1,669,182
RP6	Solar	\$1,163,394	\$1,246,165	\$1,423,590	\$1,378,987	\$1,465,797	\$1,665,995
RP7	Solar PPA + Storage	\$1,154,889	\$1,236,518	\$1,413,532	\$1,370,024	\$1,455,686	\$1,654,813
RP8	Retire Coal	\$1,183,714	\$1,267,624	\$1,467,499	\$1,356,160	\$1,438,706	\$1,646,153

viii. Discussion of Scenario Costs Results:

RP2, RP4, and RP7 are lower cost when CO_2 is assumed to be $0/ton. These resource plans use ICTs to meet the reserve margin going forward. RP4 includes retirements of McMeekin and Urquhart 3 in 2028 and has higher carbon production. RP7 includes a solar PPA plus storage in 2026. RP1, RP3 and RP5 add combined cycle generation and are generally more expensive when CO_2 costs are zero. RP3 and RP8 include retirement of a coal plant. RP8 retires all coal generating capacity by 2030 and is the least cost resource plan when CO_2 costs are $25/ton but is more expensive when CO_2 cost is $0/ton and gas prices are low.

Since RP2 is the least cost alternative under zero cost CO_2, Base Gas, and Medium DSM, it is considered the base case. Under new regulations or changes in the market, however, the base case may change. Given societal trends that are requiring more sustainable sources of clean energy, RP7 and RP8 have significant merits. The Company will continue to study the cost and benefit of portfolio alternatives that lower CO_2 emissions and promote more sources of clean energy.

ix. Resource Plan Rankings by Total Fuel Costs

The following table summarizes the 40 year levelized NPV total fuel cost rankings for all eight resource plans under the three different gas price cases and two different CO_2 price cases.

Resource Plan Rankings by Total Fuel Costs for Medium DSM

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	6	6	5	6	6	5
RP2	ICT	7	7	7	7	7	7
RP3	Retire Wateree	4	5	6	4	5	6
RP4	Retire McMeekin	8	8	8	8	8	8
RP5	Solar + Storage	2	2	2	2	2	2
RP6	Solar	5	4	4	5	4	4
RP7	Solar PPA + Storage	3	3	3	3	3	3
RP8	Retire Coal	1	1	1	1	1	1

Discussion of Resource Plan Fuel Costs Results:

One observation is how consistent the relative rank of each resource plan is with regards to total fuel costs alone. RP 5 and RP8 are consistently least cost based on a ranking of total fuel costs alone. These two resource plans add a combined cycle gas generator with its additional fixed gas transportation costs but still remain least cost based on total fuel costs. RP4 which retires McMeekin 1 and 2 and Urquhart 3 and meets the reserve margin with ICTs is consistently the most expensive.

x. Resource Plan Rankings by 2030 CO_2 Emissions

The following tables summarize the CO_2 emissions results for all eight resource plans under the three different gas price cases and two different CO_2 price cases.

Resource Plan Rankings by CO_2 for Medium DSM

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	7	7	7	7	7	7
RP2	ICT	7	7	7	7	7	7
RP3	Retire Wateree	2	2	2	2	2	2
RP4	Retire McMeekin	6	6	6	6	6	6
RP5	Solar + Storage	4	3	5	4	4	4
RP6	Solar	3	5	4	3	3	3
RP7	Solar PPA + Storage	5	4	3	5	5	5
RP8	Retire Coal	1	1	1	1	1	1

Resource Plan 2030 CO_2 for Medium DSM (K Tons)

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	11,196	11,421	13,262	10,922	11,033	11,595
RP2	ICT	11,196	11,421	13,262	10,922	11,033	11,595
RP3	Retire Wateree	10,069	10,144	10,990	9,967	9,912	10,281
RP4	Retire McMeekin	11,190	11,393	13,177	10,862	10,850	11,452
RP5	Solar + Storage	10,826	11,054	13,073	10,549	10,609	11,230
RP6	Solar	10,788	11,083	12,950	10,512	10,586	11,218
RP7	Solar PPA + Storage	10,826	11,054	12,889	10,549	10,609	11,230
RP8	Retire Coal	7,781	7,781	7,754	7,763	7,750	7,722

xi. Discussion of CO_2 Results by Resource Plan:

Under all scenarios CO_2 is lowest in RP8 which includes the retirement of all coal generation by 2030 and the addition of a new efficient combined cycle, combustion turbines, and batteries. The second lowest CO_2 occurs in RP3 which retires Wateree in 2028. The lowest value in the table is 7,754 K Tons which is a 59% reduction of CO_2 emission from year 2005. This shows that a significant reduction in CO2 can be achieved with a 3% increase in costs.

The \$25/ton CO_2 adder had the biggest impact when coupled with high gas prices. Resource Plan 4 includes a retirement of all gas steam plants and doesn't make a significant impact to total CO_2 emissions. Also, RP1 with a combined cycle plant, Resource Plan 2 with combustion turbines, and RP4 that retires three gas fired boilers have the highest CO_2 emission in 2030 and do not achieve CO_2 reduction goals.

xii. Forecast of Renewable Generation

All resource plans include a significant amount of renewables, between 8% and 21% of total generation. The values in the table are the total renewable generation by resource plan, by 10-year period for the Medium DSM, Base Gas, and $0/ton CO_2 scenarios only.

Energy from Renewable Generation by Decade (GWh)

Resource Plan ID	Resource Plan Name	2020-2029	2030-2039	2040-2049
RP1	CC	19,912	20,338	20,339
RP2	ICT	19,912	20,338	20,339
RP3	Retire Wateree	19,912	20,338	20,339
RP4	Retire McMeekin	19,912	20,338	20,339
RP5	Solar + Storage	22,570	28,758	28,452
RP6	Solar	22,191	27,941	28,307
RP7	Solar PPA + Storage	22,570	28,728	28,448
RP8	Retire Coal	20,429	35,343	59,510

The following resource plan is the least cost resource plan.

Resource Plan 2

DESC Forecast of Summer and Winter Loads and Resources - 2020 IRP
(MW)

	YEAR	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4816	4891	4847	4948	4903	5003	4955	5037	4992	5089	5043	5143	5095	5197	5148	5249	5202	5301	5252	5351	5301	5408	5357	5465	5412	5518	5467	5574	5520	5627
2	EE Impact	0	0	0	-24	-24	-48	-50	-73	-76	-97	-102	-121	-128	-147	-155	-172	-183	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199
3	Gross Territorial Peak	4816	4891	4847	4924	4879	4955	4905	4964	4916	4992	4941	5022	4967	5050	4993	5077	5019	5102	5041	5152	5090	5209	5146	5266	5201	5319	5256	5375	5309	5428
System Capacity																															
4	Existing	5689	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915
5	Existing Solar	263	0	329	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0
6	Demand Response	227	224	228	226	229	228	230	230	231	234	232	239	233	249	234	261	235	275	236	276	237	277	238	278	239	279	240	280	241	281
	Additions:																														
7	Solar Plant	67	0	118	0																										
8	Peaking/Intermediate																														
9	Baseload																														
10	Retirements	-25																													
11	Total System Capacity	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	6190	6348	6191	6349	6192	6350	6193	6351	6194	6352	6195	6353	6196
12																															
13	Total Production Capability	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	6190	6348	6191	6349	6192	6350	6193	6351	6194	6352	6195	6353	6196
Reserves																															
14	Margin (L13-L3)	1404	1248	1493	1217	1462	1188	1436	1182	1426	1157	1403	1133	1378	1113	1353	1100	1327	1089	1306	1040	1258	983.7	1203	927.7	1149	875.7	1095	820.7	1043	768.7
15	% Reserve Margin (L14/L3)	29.2%	25.5%	30.8%	24.7%	30.0%	24.0%	29.3%	23.8%	29.0%	23.2%	28.4%	22.6%	27.7%	22.0%	27.1%	21.7%	26.4%	21.3%	25.9%	20.2%	24.7%	18.9%	23.4%	17.6%	22.1%	16.5%	20.8%	15.3%	19.7%	14.2%

New resources are added to meet either a 12% summer reserve margin or a 14% winter reserve margin. Because of the higher loads in the winter and 972 MW of solar that contribute some capacity to the summer reserves but not in the winter, the need for winter reserves drives the need to add new capacity. Even then, with just a 0.7% peak load growth rate, no new resources are added until 2035 which is outside the fifteen-year window shown above.

The following plan has the lowest CO_2.

Resource Plan 8

	DESC Forecast of Summer and Winter Loads and Resources - 2020 IRP Update (MW)																														
	YEAR	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4816	4891	4847	4948	4903	5003	4955	5037	4992	5089	5043	5143	5095	5197	5148	5249	5202	5301	5252	5351	5301	5408	5357	5465	5412	5518	5467	5574	5520	5627
2	EE Impact	0	0	0	-24	-24	-48	-50	-73	-76	-97	-102	-121	-128	-147	-155	-172	-183	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199
3	Gross Territorial Peak	4816	4891	4847	4924	4879	4955	4905	4964	4916	4992	4941	5022	4967	5050	4993	5077	5019	5102	5041	5152	5090	5209	5146	5266	5201	5319	5256	5375	5309	5428
System Capacity																															
4	Existing	5689	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5446	5697	5394	5697	5394	5697	5494	5797	5494	5797	5594	5897
5	Existing Solar	263	0	329	0	448	0	448	0	448	0	448	0	448	0	448	0	452	0	456	0	456	0	465	0	474	0	483	0	492	0
6	Demand Response	227	224	228	226	229	228	230	230	231	234	232	239	233	249	234	261	235	275	236	276	237	277	238	278	239	279	240	280	241	281
	Additions:																														
7	Solar Plant	67	0	118	0											4.4		4.4				8.8		8.8		8.8		8.8		8.8	
8	Peaking/Intermediate																		523	-38					100				100		100
9	Baseload																		553	-19											
10	Retirements	-25																	-1294	5											
11	Total System Capacity	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6350	6176	6355	5972	6086	5973	6096	5974	6106	6075	6216	6076	6226	6177	6335	6278
12																															
13	Total Production Capability	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6350	6176	6355	5972	6086	5973	6096	5974	6106	6075	6216	6076	6226	6177	6335	6278
Reserves																															
14	Margin (L13-L3)	1404	1248	1493	1217	1462	1188	1436	1182	1426	1157	1403	1133	1378	1113	1357	1100	1336	870.7	1045	821.7	1006	765.7	959.9	809.7	1015	757.7	969.5	802.7	1026	850.7
15	% Reserve Margin (L14/L3)	29.2%	25.5%	30.8%	24.7%	30.0%	24.0%	29.3%	23.8%	29.0%	23.2%	28.4%	22.6%	27.7%	22.0%	27.2%	21.7%	26.6%	17.1%	20.7%	15.9%	19.8%	14.7%	18.7%	15.4%	19.5%	14.2%	18.4%	14.9%	19.3%	15.7%

III. Transmission System Assessment and Planning

DESC's transmission planning practices develop and coordinate a program that provides for timely modifications to the DESC transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the system. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for DESC's customers while meeting DESC and industry transmission performance standards.

DESC has an ongoing process to determine the current and future performance level of the DESC transmission system. Numerous internal studies are undertaken that address the service needs of customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers, 3) customers who use only transmission services on the DESC system and 4) generator interconnection services.

DESC has developed and adheres to a set of internal Long-Range Planning Criteria which can be summarized as follows:

The requirements of the DESC "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.

a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above
b. Loss of any line operating at a voltage level of 115kV or above
c. Loss of entire generating capability in any one plant
d. Loss of all circuits on a common structure
e. Loss of any transmission transformer
f. Loss of any generating unit simultaneous with the loss of a single transmission line

Outages are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.

Furthermore, DESC subscribes to the set of mandatory Electric Reliability Organization ("ERO") Standards, also known as the North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning, as approved by the NERC Board of

Trustees and the Federal Energy Regulatory Commission ("FERC").

DESC assesses and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC website www.nerc.com.

The DESC transmission system is interconnected with Duke Energy Progress, Duke Energy Carolinas, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the DESC transmission system just as system conditions on the DESC transmission system can affect other systems. DESC participates with other transmission planners throughout the southeast to develop current and future power flow, stability and short circuit models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, DESC evaluates its current and future transmission system for compliance with the DESC Long Range Planning Criteria and the NERC Reliability Standards.

Electrical transmission investments planned by DESC:

Planned Project	**Tentative Completion Date**
Thomas Island - Jack Primus 115 kV Line: Acquire R/W & Construct	Feb-20
Saluda Hydro-Denny Terrace 115kV: Broad River Rebuild	Apr-20
Hugh Leatherman 115 kV Tap: Construct	Apr-20
Lake Murray-Lexington Jct 115kV: String 1272 ACSR	May-20
Lake Murray - Michelin 115 kV: Pull new wire on existing structure / Rebuild as Double Circuit	May-20
Cope - Denmark 115 kV: Upgrade to 1272 ACSR from Denmark Sub to Str. 68	May-20
Hooks 115kV Switching Station: Construct	May-20
Urquhart - Graniteville - South Augusta 230/115 kV Tielines	Jun-20
Saluda Hydro - Denny Terrace & Lake Murray - Harbison	Oct-20
Batesburg-Gilbert 115 kV Line	Dec-20

Briggs Rd-Stevens Creek 115kV: Rebuild	Dec-20
Stevens Creek - Briggs Road Tie-line Construct	Dec-20
Bluffton - (SCPSA) Bluffton 115 kV Tie Line Construct	Dec-20
Williams Street - Park Street 115 kV: Construct	Dec-20
Pepperhill - Summerville 230 kV Construct	Jan-21
Edmund - Pelion Tap 115 kV Line	Jan-21
Church Creek-Faber Place 230kV & 115kV: Rebuild the Ashley River Crossing	May-21
Emory 230 kV Distribution Sub: Construct	May-21
Queensboro - Ft Johnson 115 kV Tap	May-21
Canadys 230 kV: Add Back-to-Back Bus Tie Breakers	Jun-21
Canadys 230 kV Sub: Reterminate Various Lines	Jun-21
Urq Jct - Toolbeck 230 kV Fold In	Dec-21
Lake Murray - Gilbert 115 kV Line	Dec-21
Lex Westside - Gilbert 115 kV Line	Dec-21
Batesburg - Ward 115 kV Line	Dec-21
Trenton - Briggs Rd 115 kV Line	Dec-21
Toolebeck – Aiken 230kV Tie: Construct	Dec-21
Coit - Gills Creek 115 kV Line: Construct	Dec-22
Burton - Yemassee 115 kV #2 Line Rebuild as Double Circuit	Dec-22
Stevens Creek-Ward-Lake Murray Line and Associated System Hardening Construct	Mar-23
Union Pier 115-13.8 kV Sub: Tap Construct	Dec-24
Canadys - Ritter 115 kV: Rebuild as 230/115 kV Double Circuit	May-27

Note: The projects listed above are the currently planned projects based on the latest assessment studies. The transmission expansion plan is continuously reviewed and may change due to changes in key data and assumptions. This summary of projects does not represent a commitment to build.

To ensure the reliability of the DESC transmission system while considering conditions on other systems and to assess the reliability of the wide-area integrated transmission grid, DESC participates in assessment studies with neighboring transmission planners in South Carolina, North Carolina and Georgia. Also, DESC on a periodic and ongoing basis participates with other transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission planners completed over the past year:

1. SERC NTWG Reliability 2019 Summer Study
2. SERC NTWG Reliability 2019/2020 Winter Study
3. SERC NTWG OASIS 2019 January Studies (19Q1)
4. SERC NTWG OASIS 2019 April Studies (19Q2)
5. SERC NTWG OASIS 2019 July Studies (19Q3)
6. SERC NTWG OASIS 2019 October Studies (19Q4)
7. SERC LTWG 2024 Future Year Study
8. CTCA 2021 Daytime Minimum, 2022 Daytime Minimum, 2024 Summer Peak – Reliability and Transfer Capability Studies
9. SCRTP 2020 Summer and 2023/24 Winter Transfer Studies

The acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group
OASIS – Open Access Same-time Information System
LTSG – Long Term Study Group
CTCA – Carolinas Transmission Coordination Arrangement
SCRTP – South Carolina Regional Transmission Planning

These activities, as discussed above, provide for a reliable and cost-effective transmission system for DESC customers and comply with Federal regulations.

Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative ("EIPC") was initiated by a coalition of regional Planning Authorities (including DESC). These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the majority of the Eastern Interconnection.

The EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection.

The EIPC purpose is to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes are informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

Distributed Generation Integration

All levels of the existing electric infrastructure, standards, and operating protocols were originally designed around a fully dispatchable generation fleet required to satisfy variable load conditions. Equipment configurations and operating standards have been designed to ensure grid reliability and stability through the control of system frequency and voltage. In contrast, Solar PV generation systems are intermittent where energy output is variable with limited dispatch capability. Further, traditional generation facilities are typically large centralized plants with high MW ratings while solar PV generating facilities are smaller in size and, in many cases, installed at the distribution level by the end user (e.g., a homeowner, business, or other non-utility entity) – often mounting the PV panels on the roof of a building or on smaller scale developer-built sites. As the movement towards clean energy grows, the Company expects that power from solar PV installations may be injected onto its system from hundreds or even thousands of interconnection points that may either be at the transmission level or at on the distribution level. To accommodate these changes, generation facilities, transmission grids, and distribution systems must allow for two-way power flows all while maintaining the highest level of reliability possible. The Company continues to study this paradigm shift in generation technology and its impact on the Company's transmission grid and distribution system, and the results of this work could require design modifications to assure system stability and reliability. Examples may include partial system re-configuration and/or deployment of new technologies such as batteries, synchronous condensers, and static synchronous compensators ("STATCOM").

DESC plans to continue to study the issues associated with solar PV integration described above. The results of those studies will be published in future IRP's.

IV. Conclusions

The results in this document reflect that in the near term the Company does not need to make any major changes to the baseload generation fleet in order to meet customer's energy and capacity needs in a safe, reliable, and cost-effective manner. However in an effort to produce a more sustainable future, the Company is implementing or evaluating upgrading its distribution network with projects like AMI, replacing older peaking units with quick-start, flexible, and reliable generation, expanding DSM and studying its transmission system to minimize the impact of eventual steam unit retirements and allow for additional intermittent renewable generation.

Some useful results in the Resource Plan Analysis include that RP2 was the least cost plan under all DSM cases, with base gas and \$0/ton CO_2, though the cost difference between all cases was modest. RP7 and RP8 were least cost plans under numerous scenarios. RP8 resulted in the least carbon impact under all scenarios. All resource plans include the addition of combustion turbines or combined cycle plants but Resource Plans 5 – 8 also add renewables. RP2 which adds only combustion turbines, Resource Plan 7 which has solar with storage, and RP8 which retires coal, rank the least cost depending upon the sensitivity selection. RP8 has the lowest 2030 CO_2 emissions by a significant margin, and the lowest cost in some scenarios. All resource plans were within 3% of levelized NPV of each other when the assumptions about DSM, CO_2 and gas were held constant. These differences indicate that the relative rankings could change based on updated information in the future. While the Company makes observations and conclusions as to which resource plan results in the least cost, the results do not reflect a decision by the Company for its path forward

Since the 2019 IRP and 2019 Potential Study, DESC has implemented a much larger commitment to AMI which will increase the potential for deployment of additional cost-effective DSM, which includes both EE and DR. AMI will allow the Company to target new and specific demand response programs for study. End of life retirement of some of the Company's older combustion turbines are the only near-term issue that may adversely impact the Company's ability to maintain the proper level of planning reserves. The Company plans to continue to study this issue and will inform the PSC of its conclusion regarding these older combustion turbines after the final analysis is complete. At this time, however, no immediate action is needed for resource retirements or additions based on the IRP. This IRP does indicate that several potential retirements and other resource plans are viable and will be studied over the next few years. Expenditures over the IRP time horizon will be primarily toward environmental compliance, reliability of supply, grid reliability and the continued shift toward renewable resources. The Company will continue to study these alternatives in detail.

On an energy basis, photovoltaic solar technology is becoming more cost-competitive with traditional forms of generation. Currently, stand-alone solar does not meet all of the needs of a highly dynamic and critical infrastructure system like the electric grid. As previously mentioned, solar provides little winter peaking capacity. It will take innovation and research to find a cost-effective combination of combustion turbine and energy storage technologies to provide reliable clean energy supply for the future. Using the results of several resource plans and scenarios provides a reasonable means of estimating the cost benefit ratio for CO_2 reductions. Comparing RP2 and RP8 shows that a 3% increase in costs could result in significantly better CO_2 reduction by 2030 of 59% reduction verses RP2's 39%, both from 2005 levels. The only substantive CO_2 reductions are a result of reducing or eliminating energy generated from coal resources as shown in RP3 and RP8.

The IRP process is designed to develop and evaluate potential resource plans under various scenarios to understand risks, costs and environmental impacts to reserve margins. Given the dynamic nature of the current electric power industry with respect to societal trends, customer preferences, technological advances, and environmental regulations, it is important that Company remain flexible with respect to future expansion plans. As such, the DESC resource plans identified in this 2020 IRP present several plausible paths the Company may or may not elect to pursue. What's most imperative is that the Company remain agile regarding management of its electric generation portfolio in response to changing energy supply and customer usage.

The Charleston Metropolitan area is poised for EV growth. Several factors are promoting EV growth in the strongest market ahead of more rural areas in the DESC service territory. The Company anticipates that the growth in the Charleston area will continue to gain strength. Similar adoption rates are expected to follow in the Columbia, Hilton Head and Aiken areas. The local increased energy demand will certainly require adaptation initially in all urban areas.

Urban distribution systems will need additional support from automation as adoption increases.

In the next 15 years, DESC will be working toward creating the infrastructure that opens the way for lower cost generation and non-emitting resources, but those steps must also be affordable. However, with a commitment to a more sustainable energy future, the Company needs to upgrade its distribution network through measures such as rolling out Advanced Metering Infrastructure, converting some of its older peaking generation to more reliable and quick- start peaking generation, continuing to expand DSM, and studying transmission system to minimize the impact of eventual steam unit retirements and additional intermittent renewable generation.

Appendix A

Intervenor Provided Resource Plans and Scenarios

As a part of the Dominion Energy/SCANA merger settlement DESC agreed that "During the development of the IRP, intervenors in the previous year's IRP can request (via the Office of Regulatory Staff ("ORS")) that the SCE&G evaluate a limited number of alternative resource plans for modeling during the IRP development. For purposes of this condition, the limited number of alternative resource plans required shall not exceed five and shall be agreed upon by SCE&G in consultation with ORS." The following resources and scenarios were suggested by the intervenors. Although these resource plans utilized many of the same data inputs, no direct comparisons to DESC's resource plans were possible due to the low resource cost information provided by the third parties, which in DESC's view, results in a low portfolio cost bias and prevents a practical comparison.

The following table lists the resources examined in the intervenors' resource plans.

Resource	**Capital Cost 2020 $/kW**	**Description**	**Source of Data**
Stand Alone Battery PPA	N/A	100 MW with 4 hour duration	2019 NREL Low Technology Cost Scenario pricing
Solar PPA	N/A	Various Sizes	2019 NREL Low Technology Cost Scenario pricing
Solar + Storage PPA	N/A	400 MW Solar + 100 MW Battery Storage	2019 NREL Low Technology Cost Scenario pricing
ICT	1097	93 MW aeroderivative	Dominion Energy Services - Generation Construction Financial Management & Controls
Capacity Purchases	N/A	50 MW increments	DESC estimates

These five resources were combined in various ways to develop five resource plans, some of which consider the retirement of some existing generating units. The five resource plans are listed in the following table with a description of each resource plan. Wateree and Williams are retired when they reach their end of life, which is years 2044 and 2047 respectively, if not retired earlier.

Intervenor Resource Plan ID	Intervenor Resource Plan
SBA 1	Solar PPA, ICT, Base DSM
SBA 2	Williams Retirement, 1.25% DSM, Standalone Battery Storage PPA, Solar PPA
SBA 3	Williams and Wateree Retirement, 1.25% DSM, Capacity Purchases, Solar PPA, Standalone Battery Storage, Solar+Storage PPA
SBA 4	McMeekin and Urquhart 3 Retirement, 1.25% DSM, Solar PPA, Standalone Battery Storage
SBA 5	Solar PPA in 2021, Standalone Battery Storage PPA, Base DSM

Intervenor Resource Plan Definitions

Resource Plan SBA 1: In this resource plan a 400 MW Solar PPA is added in 2026. 93 MW of combustion turbines are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 2: In this resource plan Williams is retired in year 2028. 831 MW Solar PPA, 358 MW Storage, and DSM equal to 1.25% of retail sales plus 43 MW of DR are added. 100 MW standalone storage are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 3: In this resource plan Williams and Wateree are retired in 2026. 1774 MW Solar PPA, 603 MW Storage, 500 MW capacity purchases and DSM equal to 1.25% of retail sales plus 43 MW of DR are added to replace the retired capacity and energy. Capacity purchases terminate in 2029 and are replaced by a 500 MW standalone battery storage PPA. 400 MW Solar +100 MW Storage PPAs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 4: In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2029. The retired capacity and energy is replaced by 64 MW of standalone battery storage, 94 MW of solar PPA, and DSM equal to 1.25% of retail sales plus 43 MW of DR. 100 MW standalone battery storage PPAs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 5: In this resource plan 200 MW of solar PPA is added in 2021. 43 MW of DR is added in 2029. Base level of DSM is used in this resource plan. 100 MW standalone battery storage is added to maintain the 14% winter reserve margin during the modeling period.

PPA Price Assumptions

The intervenors specified that the renewable costs used in modeling their five resource plans be based on the NREL Annual Technology Baseline database "Low Technology Cost Scenarios." The results would have been more useful had the intervenors specified that DESC use the "Mid Technology Cost Scenarios." Below are NREL definitions for their two scenarios:

- Mid Technology Cost Scenario: based on the median of literature projections of future CAPEX; O&M technology pathway analysis
- Low Technology Cost Scenario: based on the low bound of literature projections of future CAPEX and O&M technology pathway analysis.

The CAPEX forecast for solar under the "Low Technology Cost Scenario" drops an aggressive 61% from 2020 to 2050. Under the "Mid Technology Cost Scenario" the CAPEX forecast for solar drops a more realistic 36% from 2020 to 2050. By specification, the resulting levelized cost for all five intervenor resource plans is very likely to be understated.

Methodology

The incremental revenue requirements associated with each of the five intervenor resource plans was computed using the PROSYM computer program to estimate production costs and a Microsoft® Excel capital cost model to calculate the associated capital costs. The capital cost model is combined the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon.

Demand Side Management (DSM) Assumptions

Two DSM cases were used in resource plans provided by the intervenors. Medium DSM is based on the results of the 2019 Potential Study and is used for Resource Plans 1 and 5. DSM specified in Resource Plans 2 – 4 requires that DSM grows to 1.25% by 2024. It should be noted that DSM levels above those provided within the 2019 Potential Study, are not likely to be achievable and cost-effectiveness is unknown. It should also be noted that the costs used to model the 1.25% DSM in Resource Plans 2 – 4 are only estimates. No comprehensive study or program analysis has been completed to determine the actual costs to achieve 1.25% savings and such costs can be expected to grow exponentially as higher and higher levels of energy savings are sought.

Emissions and Fuel Sensitivity

Each resource plan was evaluated using three gas price forecasts plus \$0 and \$25 per ton CO_2 costs. The combination of the three gas price assumptions and two CO_2 cost assumptions created 6 different scenarios. The high gas price forecast is the 2019 EIA gas price forecast. The base gas and low gas scenarios are based on NYMEX gas prices for years 2020-2022 then escalated at two different rates. The base escalation rate is derived from the EIA gas price forecast. The low gas scenario escalation rate is half of the base gas escalation rate. The two CO_2 assumptions used were \$0/ton and \$25/ton.

Intervenor Resource Plan Rankings

The following tables summarizes the 40 year levelized NPV cost results for all five resource plans under the three different gas price cases and two different CO_2 price cases.
(1 - Green= Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan ID	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
SBA 1	4	4	5	4	5	5
SBA 2	1	1	1	2	2	2
SBA 3	3	3	2	1	1	1
SBA 4	5	5	4	5	4	4
SBA 5	2	2	3	3	3	3

40 Year Levelized NPV of the Intervenor Resource Plans

Resource Plan ID	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
SBA 1	\$1,181,917	\$1,259,710	\$1,426,579	\$1,396,358	\$1,475,537	\$1,669,170
SBA 2	\$1,142,465	\$1,211,484	\$1,368,241	\$1,333,510	\$1,406,644	\$1,583,127
SBA 3	\$1,179,934	\$1,236,930	\$1,382,570	\$1,329,021	\$1,389,003	\$1,544,806
SBA 4	\$1,192,393	\$1,261,454	\$1,421,922	\$1,401,112	\$1,472,960	\$1,651,763
SBA 5	\$1,157,146	\$1,233,152	\$1,400,031	\$1,372,049	\$1,451,312	\$1,639,753

Discussion of Cost Results:

Resource Plans 2 and 3 are least cost as modeled. Resource Plans 2 through 4 assumed a level of DSM that is not cost effective Therefore, only Resource Plans 1 and 5 provide meaningful results within the constraints specified.

Since \$0/Ton CO_2 and Base Gas is the most likely scenario, Resource Plan 1 is the least cost of these scenarios when only Resource Plans 1 and 5 are considered.

2030 CO_2 Emissions Rankings

The following tables summarize the CO_2 emissions results for all five resource plans under the three different gas price cases and two different CO_2 price cases. Green shading denotes the lowest CO_2 production and the number 1 ranking. Blue is second lowest, and brown is the highest CO_2 production at the number 5 ranking

Resource Plan ID	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
SBA 1	4	4	4	4	4	4
SBA 2	2	2	2	2	2	2
SBA 3	1	1	1	1	1	1
SBA 4	3	3	3	3	3	3
SBA 5	5	5	5	5	5	5

2030 CO_2 Emissions (K tons)

Resource Plan ID	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
SBA 1	10,791	11,096	12,940	10,526	10,569	11,213
SBA 2	8,943	9,082	10,551	8,649	8,722	9,291
SBA 3	6,990	6,986	7,493	6,907	6,904	7,312
SBA 4	10,715	11,045	12,593	10,456	10,495	11,036
SBA 5	11,111	11,281	13,070	10,770	10,794	11,474

Discussion of CO_2 Results:

The resource plan with the least CO_2 emission Resource Plan 3 under all scenarios. Resource Plan 3 included 1,294 MW of coal retirements. The highest emitting resource plan in all scenarios was Resource Plan 5 which adds 200 MW of solar in 2021. The CO_2 emissions in resource plans 2, 3, and 4 are low because the 1.25% DSM scenario was specified and used in these resource plans in addition to coal-fired generation unit retirements in plans 2 and 3. It should also be noted that the costs used to model the 1.25% DSM in Resource Plans 2 through 4 are only estimates. No comprehensive study or program analysis has been completed to determine the actual costs to achieve 1.25% savings.

Prepared for:

Dominion Energy South Carolina

220 Operations Way

Cayce, SC 29033

Independent Review of the 2020 DESC IRP

Prepared by:

Charles River Associates

200 Clarendon Street

Boston, Massachusetts 02116

Date: June 3, 2020

CRA Project No. 30299

Disclaimer

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List of Acronyms

AEO	Annual Energy Outlook
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachia
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
COPT	Capacity Outage Probability Table
CPP	Critical Peak Pricing
CRA	Charles River Associates
DESC	Dominion Energy South Carolina
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EPA	Environmental Protection Agency
EV	Electric Vehicle
FPL	Florida Power & Light
GDP	Gross Domestic Product
GWh	Gigawatt Hour
HDD	Heating Degree Days
HVAC	Heating Ventilation and Cooling
ICT	Internal Combustion Turbine
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt Hour
LCOE	Levelized Cost of Energy
LOLE	Loss of Load Expectation
LTCE	Long Term Capacity Expansion
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NPVRR	Net Present Value of Revenue Requirement
PPA	Power Purchase Agreement
PURPA	Public Utility Regulatory Policy Act
QF	Qualifying Facility (PURPA)
RMSE	Root Mean Squared Error
RP	Resource Plan
SBA	Solar Business Alliance
SERC	SERC Reliability Corporation
SIC	Standard Industrial Classification
TCR	Total Cost Recovery
TECO	Tampa Electric
ToU	Time of Use
TVA	Tennessee Valley Authority
UPC	Use Per Customer
VOM	Variable Operations and Maintenance
SAS	Statistical Analysis System

1. Executive Summary

This report contains Charles River Associates' ("CRA") independent evaluation of Dominion Energy South Carolina's ("DESC") 2020 Integrated Resource Plan ("IRP"). An IRP is a planning document that describes a utility's long-term customer demand requirements and its plan to meet those needs in a prudent and cost-effective manner. DESC filed its 2020 IRP with the Public Service Commission of South Carolina on February 28, 2020. The 2020 IRP evaluated the 40-year system costs of thirteen different resource plans under a range of fuel, carbon, and load assumptions. DESC ultimately recommended a portfolio that makes no major changes to the current generating fleet and relies primarily on new natural gas combustion turbines to meet growing peaking requirements.

Long-term planning exercises like the 2020 DESC IRP necessarily rely on a set of market assumptions related to views on the economy, fuel prices, capital costs, and many other cost and performance parameters for the utility's system. Once these assumptions are developed, resource planners rely on certain methods and tools, such as statistical analysis, production cost models, and cost of service accounting, to estimate future system costs and annual revenue requirements for the utility. When conducting an IRP, planners generally perform this analysis while considering a range of potential future resource options against a range of possible future market outcomes.

CRA was retained by DESC as part of a settlement agreement with the South Carolina Solar Business Alliance ("SBA") to provide an independent review of the approach and methodology used by DESC in the preparation of its 2020 IRP. More specifically, CRA's remit was to review the reasonableness of DESC's load forecast, reserve margin methodologies, and portfolio modeling. Beyond opining on the reasonableness of DESC's approaches and methodologies, CRA has, in some cases, suggested potential actions that DESC may take in future IRPs to improve the clarity of the filing or the analysis itself.

In general, CRA judged an assumption or approach to be reasonable when it was supported by recent third-party studies, publicly available market data, planning documents from nearby utilities, or CRA's own industry experience. CRA judged a model or methodology to be reasonable if it is commonly used across the industry and provides statistically or mathematically sound results.

1.1. Load Forecasting

Chapter 5: Load Forecasting reviews the annual energy and seasonal peak forecasts used in the 2020 DESC IRP. In this chapter, CRA evaluates the methods and assumptions used to estimate the growth rates for major residential, commercial, and industrial load segments. CRA also evaluates how the demand side management ("DSM") forecast is integrated in the load forecast to develop the final system requirements. CRA reviews the statistical outputs of DESCs regression models, compares the 2020 DESC forecast assumptions to historical values, and benchmarks the forecast against assumptions used by regional utilities.

CRA's independent report focuses on the long-range forecasts prepared for the residential, commercial, and industrial classes because these three groups represented between 91-94% of DESC loads over the past 15 years.

CRA conducted interviews and reviewed testimony of DESC load forecasting experts and was provided data in native format (e.g., Excel) containing historical sales data by customer class, seasonal peak data by customer class, peak seasonal load calculations, DSM amounts, and load forecasts used in the portfolio modeling of the 2020 IRP. CRA also reviewed statistical outputs from the SAS models used to perform the regression analysis and macroeconomic forecast that drives customer sales and growth in the 2020 IRP.

CRA reviewed DESC's long-range load forecast, DSM program, and associated analyses and has concluded the following:

- DESC forecasted growth in sales and customers using regression analysis, a common econometric method that is widely-applied for this purpose by electric utilities.
- The models and methods used by DESC to forecast residential, commercial and industrial demand are reasonable. The equations for these customer classes use descriptive variables that are shown to be significant and have explainable impacts on the dependent variables. The statistical outputs demonstrate that the models are properly specified and have reasonable goodness of fit.
- DESC forecasted growth in seasonal peak demand through evaluation of historical contributions of different customer classes to seasonal peak-hour loads. The values relied upon for the 2020 IRP are reasonable. 2020 peak hour load by customer class reflects the levels and trends observed in the historical data.
- DESC's 2020 IRP provided a reasonable Base case view, and DESC evaluated a range of load forecasts that capture a reasonable range of uncertainty around the Base case view. The overall range of load scenarios considered could be expanded in future IRP analyses to include lower probability events.

1.2. Reserve Margin

Chapter 6: Reserve Margin reviews DESC's approach to estimating the capacity requirements needed to maintain system reliability used in the 2020 IRP. In this chapter, CRA evaluates DESC's approach to determining seasonal peaking requirements by evaluating supply- and demand-side risk in the winter and summer season and comments on DESC's convention of splitting seasonal reserve margins into base and peaking requirements. CRA compares DESC's approach to methods used by others in the industry and benchmarks DESC's reserve requirements against regional utilities.

CRA reviewed DESC's reserve margin policy and supporting documents and analyses, conducted interviews, and reviewed testimony of DESC resource planning and load forecasting experts regarding the reserve margin policy and associated analyses.

CRA reviewed DESC's reserve margin policy and associated analyses and has concluded the following:

- DESC has demonstrated that summer and winter demand-side risk are significantly different from each other and that seasonal planning reserve margin targets should reflect such differences. This is reasonable, consistent with many other utilities in the region, and in line with broader industry trends.
- DESC has demonstrated that peak events, especially in the winter, are characterized by large load spikes with limited duration. Thus, it is reasonable to consider different base and peaking planning targets, but DESC should consider more robustly supporting its criteria to define the base reserve margin in the future.
- DESC's overall evaluation of demand-side risk is based on sound econometric principles and industry-standard practice for performing load uncertainty analysis.

- DESC's overall evaluation of supply-side risk is reasonable, but additional rationale for the selection of the right supply-side risk threshold would improve confidence in the policy standard.
- DESC's loss of load expectation ("LOLE") study was based on an industry-standard metric of 0.1 days per year or 1 day in ten years, and the application of both supply-side risk and demand-side load shapes in the study were reasonable. In future LOLE study reviews, DESC may consider evaluating hourly granularity and including weather risk to further test the robustness of its reserve margin policy.

1.3. Portfolio Analysis

Chapter 7: Portfolio Analysis reviews DESC's process for modeling system dispatch and evaluating the long-term system costs of different resource alternatives. In this chapter, CRA evaluates the capital, fixed, and variable cost assumptions for new generation resources, along with commodity prices and other market inputs that are included in DESC's estimate of system costs. CRA evaluates the tools and methods used by DESC to simulate system dispatch and calculate system costs and considers the reasonableness of the range of scenarios and portfolios included in the IRP. CRA compares DESC's input assumptions to 3rd party studies, recent market data, assumptions used by regional utilities, and CRA's own industry experience.

CRA received and reviewed DESC's revenue requirement spreadsheets, along with a wide range of data items and reports provided by DESC staff in native format supporting these calculations. The files were primarily Microsoft Excel format, containing modeling assumptions describing the load and DSM assumptions, DESC "green-book" assumptions, unit fuel and operating costs used in dispatch modeling, the cost outputs of the PROSYM model simulations, and fixed cost assumptions used to estimate revenue requirements.

CRA also reviewed DESC's Expansion Plan files, which detail existing and new resources for each resource plan, DSM, and load over the study period and demonstrate how reserve margins are maintained in PROSYM. CRA has reviewed annual unit output, including fuel costs, fuel burn and generation, for select resource plans under various scenarios to ensure consistency with input assumptions described in the IRP document.

CRA further conducted multiple interviews with DESC experts and reviewed documents produced by these experts describing the approach and assumptions used for modeling solar technology in the 2020 IRP.

CRA reviewed DESC's portfolio modeling assumptions and associated analyses and has concluded the following:

- DESC's overall approach used standard industry tools and was comprehensive in its scope. In the future, DESC may consider enhancing its tools and capabilities to ensure that the widest possible range of options is evaluated.
    - PROSYM was a reasonable tool for the 2020 IRP, but future IRPs may consider incorporating another tool that allows for least cost optimization of capacity expansion.
    - DESC has demonstrated that the IRP evaluated 94 different scenario-portfolio combinations. The portfolios evaluated a wide range of resource options, including retirement of existing resources. In the future, DESC may consider a broader assessment of existing resource options with fuller support for specific retirement dates evaluated.

  - DESC considered a reasonable set of new resource options as relevant replacement technologies and developed a number of scenarios and portfolios that used assumptions provided by the South Carolina SBA.
- The IRP assumptions for new resource options were generally reasonable and consistent with current market trends and standard practice in the industry.
  - The capital and operating costs assumed by DESC for new generation supply were generally reasonable and consistent with assumptions from similar IRPs in the industry; however treatment of the investment tax credit ("ITC") was conservative for new DESC-owned solar resources added in 2026. In addition, fixed O&M costs for solar and batteries owned by DESC were understated.
  - Unit performance assumptions for thermal, renewable, and storage resources were reasonable and consistent with assumptions from similar IRPs in the industry. DESC's characterization of flexible solar resources was reasonable, and DESC did not disadvantage solar supply as a resource type by allowing curtailment.
  - The cost and terms of Power Purchase Agreements ("PPAs") modeled in the IRP were reasonable and consistent with the 2019 NREL Document relied upon by DESC.[1]
- DESC evaluated its portfolios across a range of key uncertainties, including fuel costs, carbon pressure, and customer demand. DESC's selection of scenario variables was reasonable, and input ranges reflect an appropriate band of uncertainty. However, future IRPs may consider evaluating a wider range of load outlooks and natural gas prices.
- DESC has demonstrated that the DSM resources identified in the 2019 Potential Study are included in the 2020 IRP portfolios and result in the appropriate amount of energy and peak savings.
- DESC has demonstrated that the input assumptions described in the IRP and supporting documents are reflected in the estimated system costs. The resource plans modeled in PROSYM match the descriptions in the IRP, and the model outputs reflect reasonable and appropriate calculations.

[1] NREL (National Renewable Energy Laboratory). 2019. 2019 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2019.

2. Purpose and Scope of the Report

This report contains Charles River Associates' ("CRA") independent evaluation of Dominion Energy South Carolina's ("DESC") 2020 Integrated Resource Plan ("IRP"). An IRP is a planning document that describes a utility's long-term customer demand requirements and its plan to meet those needs in a prudent and cost-effective manner. DESC filed its 2020 IRP with the Public Service Commission of South Carolina on February 28, 2020. The 2020 IRP evaluated the 40-year system costs of thirteen different resource plans under a range of fuel, carbon, and load assumptions. DESC ultimately recommended a portfolio that makes no major changes to the current generating fleet and relies primarily on new natural gas combustion turbines to meet growing peaking requirements.

Long-term planning exercises like the 2020 DESC IRP necessarily rely on a set of market assumptions related to views on the economy, fuel prices, capital costs, and many other cost and performance parameters for the utility's system. Once these assumptions are developed, resource planners rely on certain methods and tools, such as statistical analysis, production cost models, and cost of service models, to estimate future system costs and annual revenue requirements for the utility. When conducting an IRP, planners generally perform this analysis while considering a range of potential future resource options against a range of possible future market outcomes.

CRA was retained by DESC as part of a settlement agreement with the South Carolina SBA to provide an independent review of the approach and methodology used by DESC in the preparation of its 2020 IRP. More specifically, CRA's remit was to review the reasonableness of DESC's load forecast, reserve margin methodologies, and portfolio modeling. Beyond opining on the reasonableness of DESC's approaches and methodologies, CRA has, in some cases, suggested potential actions that DESC may take in future IRPs to improve the clarity of the filing or the analysis itself.

In general, CRA judged an assumption or approach to be reasonable when it was supported by recent third-party studies, publicly available market data, planning documents from nearby utilities, or CRA's own industry experience. CRA judged a model or methodology to be reasonable if it is commonly used across the industry and provides statistically or mathematically sound results.

3. Organization of the Report

CRA's independent report is broadly organized across the three topics that are identified in its mandate.

- **Chapter 5: Load Forecasting** reviews the annual energy and seasonal peak forecasts used in the 2020 DESC IRP. In this chapter, CRA evaluates the methods and assumptions used to estimate the growth rates for major residential, commercial, and industrial load segments. CRA also evaluates how the demand-side management ("DSM") forecast is integrated in the load forecast to develop the final system requirements. CRA reviews the statistical outputs of DESC's regression models, compares the 2020 DESC forecast assumptions to historical values, and benchmarks the forecast against assumptions used by regional utilities.
- **Chapter 4: Reserve Margin** reviews DESC's approach to estimating the capacity requirements needed to maintain system reliability used in the 2020 IRP. In this chapter, CRA evaluates DESC's approach to determining seasonal peaking requirements by evaluating supply- and demand-side risk in the winter and summer season and comments on DESC's convention of splitting seasonal reserve margins into base and peaking requirements. CRA compares DESC's approach to methods used by others in the industry and benchmarks DESC's reserve requirements against regional utilities.
- **Chapter 7: Portfolio Analysis** reviews DESC's process for modeling system dispatch and evaluating the long-term system costs of different resource alternatives. In this chapter, CRA evaluates the capital, fixed, and variable cost assumptions for new generation resources, along with commodity prices and other market inputs that are included in DESC's estimated system costs. CRA evaluates the tools and methods used by DESC to simulate system dispatch and calculate system costs and considers the reasonableness of the range of scenarios and portfolios included in the IRP. CRA compares DESC's input assumptions to third party studies, recent market data, assumptions used by regional utilities, and CRA's own industry experience.

CRA begins each chapter by providing a summary of its key findings and a description of the steps taken as part of its independent review. Following this summary, CRA provides an overview of the subject matter at hand that describes the approach taken and assumptions used by DESC in its 2020 IRP. Each chapter is then organized into sub-sections that address distinct and material components of the 2020 IRP forecast and supporting analysis. Under each sub-section, CRA's report identifies key assumptions and methods relied upon by DESC and provides commentary describing the reasonableness of these assumptions and methods.

4. CRA's Approach to Report Development

CRA's approach starts with the 2020 IRP document itself. CRA staff reviewed each section of the IRP and identified the key inputs, methods, and approaches taken by DESC in the 2020 IRP. CRA then evaluated these key inputs against a range of publicly available information and CRA's own industry experience to ensure that they were reasonable and unbiased.

An IRP document necessarily summarizes a great deal of work and analysis from across different functions within a utility. CRA engaged in a series of interviews and data exchanges with different DESC experts covering the load forecast, reserve margin calculation, DSM assumptions, and portfolio modeling elements of the 2020 IRP. As part of this exchange, CRA received and reviewed a wide range of documents provided in native format, primarily Microsoft Excel, that contained assumptions to the load forecasting models, PROSYM inputs and outputs, and other supporting calculations used to estimate portfolio supply and demand parameters used in the 2020 DESC IRP.

CRA also reviewed the revenue requirement model used to estimate and compare total system costs between the different portfolio simulations. CRA confirmed that modeled outputs from PROSYM reflected the inputs described in the IRP and that the cost and performance parameters assumed for new resources in the portfolio cost analysis were reasonable.

CRA also conducted a call with members of the South Carolina Solar Business Alliance. On that call, SBA members were invited to provide questions about each element of the IRP document. CRA has endeavored to address these items, where appropriate, as part of this report.

4.1. Interviews

CRA conducted a series of interviews with DESC experts as part of its independent evaluation of the load forecast, reserve margin, and portfolio modeling assumptions in the IRP. CRA interviewed the following individuals:

- Eric Bell - Manager, Economic Resource Commitment, Resource Plan & Portfolio Modeling Expert
- Therese Griffin – Manager, Energy Efficiency and Demand Side Management, DSM & Efficiency Expert
- Joseph M. Lynch – Manager, Resource Planning, Load Forecasting Expert
- Joseph Stricklin – Senior Analyst, Resource Planning, Load Forecasting Expert
- Sheryl Shelton – Manager, Demand Side Management Administration, DSM & Efficiency Expert
- James Neely – Senior Engineer, Resource Plan & Portfolio Modeling Expert

4.2. Data Request

DESC provided CRA with past expert testimony and numerous internal documents describing detailed portfolio inputs, supporting calculations, and the methodologies used by staff to develop the 2020 DESC IRP. These are summarized below by report section:

- **Chapter 5 Load Forecast.** CRA was provided historical sales data by customer class, seasonal peak data by customer class, peak seasonal load calculations, DSM forecasts, and load forecasts used in the portfolio modeling of the IRP. CRA was provided with the past DESC expert testimony, including the "Peak Demand Study" and the testimony of Joseph M. Lynch, Ph.D. regarding that report.[2] CRA also reviewed the "2019 Potential Study" developed by ICF International and accepted by the South Carolina Public Service Commission (the "Commission") as part of Docket No. 2019-2-E. CRA was also provided with the "Energy Forecast Documentation Short Range and Long Range for 2020 Budget and Beyond," a document describing the 2020 load forecasting process, provided by Joseph M. Lynch and Joseph Stricklin, and statistical outputs from the SAS models used to perform the regression analysis and macroeconomic forecast that drives customer sales and growth in the 2020 IRP.

- **Chapter 6 Reserve Margin**. CRA was provided DESC's reserve margin policy and supporting documents and analyses, including the "2018 Reserve Margin Study," the "Loss of Load Expectation Study," and the testimony of Joseph M. Lynch, Ph.D. regarding both reports.[3] CRA also was provided the "Operating Manual for the VACAR Reserve Sharing Agreement"
- **Chapter 7 Portfolio Modeling**. CRA was provided DESC's revenue requirement spreadsheets, which combine PROSYM output with capital cost calculations to produce total system costs, along with a wide range of data items and reports provided by DESC staff in native format supporting these calculations. This supporting data included select PROSYM outputs, modeling assumptions describing the load and DSM assumptions in each scenario, fuel and operating costs used in dispatch modeling, and fixed cost assumptions. CRA also received DESC's "green-book" assumptions sheets that provide resource characteristics by technology type, as well as the levelized cost calculation used by DESC to develop PPA costs for solar and battery storage.

  CRA was provided DESC's Expansion Plan files, which detail existing supply, new resources for each resource plan, DSM, and load over the study period and demonstrate how reserve margins are maintained in PROSYM over time as resources are added and retired from the system.

  CRA was provided documents produced by DESC experts describing the approach and assumptions used for modeling solar technology in the 2020 IRP including "The Capacity Benefits of Solar QFs 2018 Study" and the supporting testimony of Joseph M. Lynch, Ph.D. regarding that report.[4] CRA was also provided the "The Capacity Benefit of Solar QFs 2019 Study" and supporting responses of James Neely as part of Docket No. 2019-226-E.[5]

[2] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

[3] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

[4] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

[5] Response 2-15 from James Neely, Dominion Energy South Carolina Inc, Office of Regulatory Staff's Second and Continuing Request for Production of Books, Records, and Other Information. Docket No. 2019-226-E

5. Load Forecasting

5.1. Key Findings

CRA reviewed DESC's long-range load forecast, DSM program, and associated analyses and has concluded the following:

- DESC forecasted growth in sales and customers using regression analysis, a common econometric method that is widely-applied for this purpose by electric utilities.
- The models and methods used by DESC to forecast residential, commercial and industrial demand are reasonable. The equations for these customer classes use descriptive variables that are shown to be significant and have explainable impacts on the dependent variables. The statistical outputs demonstrate that the models are properly specified and have reasonable goodness of fit.
- DESC forecasted growth in seasonal peak demand through evaluation of historical contributions of different customer classes to seasonal peak-hour loads. The values relied upon for the 2020 IRP are reasonable. 2020 peak hour load by customer class reflects the levels and trends observed in the historical data.
- DESC's 2020 IRP provided a reasonable Base case view, and DESC evaluated a range of load forecasts that capture a reasonable range of uncertainty around the Base case view. The overall range of load scenarios considered could be expanded in future IRP analyses to include lower probability events.

5.2. Scope of Review

CRA's report focuses on the long-range forecasts prepared for the residential, commercial, and industrial customer classes because these three groups have represented between 91% and 94% of DESC loads over the past 15 years.

CRA conducted interviews and reviewed supporting documents provided by DESC Staff. CRA reviewed the "Peak Demand Study" and the testimony of Joseph M. Lynch, Ph.D. regarding that report.[6] CRA also reviewed the "2019 Potential Study" developed by ICF International and accepted by the Commission as part of Docket No. 2019-2-E. Finally, CRA has reviewed "Energy Forecast Documentation Short Range and Long Range for 2020 Budget and Beyond," a document describing the 2020 load forecasting process provided by Joseph M. Lynch and Joseph Stricklin.

In addition to these documents, CRA was provided data in native format (e.g., Excel) containing historical sales data by customer class, seasonal peak data by customer class, peak seasonal load calculations, DSM amounts, and load forecasts used in the portfolio modeling of the 2020 IRP. CRA also reviewed statistical outputs from the SAS models used to perform the regression analysis and macroeconomic forecast that drives customer sales and growth in the 2020 IRP.

CRA's review has focused on the reasonableness of the following elements of DESC's load forecast:

- The econometric analysis used to estimate the impact of macroeconomic drivers on growth in customers and load in the DESC service territory;

[6] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

- DESC's approach to estimating peak loads in the summer and winter seasons based on the assumed growth in customers and sales;
- That DSM savings assumed and the relationship to the sales and peak impacts described in the ICF 2019 DSM Potential Study;
- The range of load forecasts modeled in the 2020 IRP.

5.3. DESC Approach to Load Forecasting

DESC, like many other utilities, develops a long-term forecast of electricity sales and customer growth by performing an econometric analysis of historical usage by different customer classes. This technique, known as regression analysis, evaluates the historic relationship between explanatory variables (e.g., weather, price, and observed macroeconomic indicators such as economic growth, housing starts, personal income) and dependent variables, which in this case were historic rates of customer growth and electricity sales. CRA reviewed the long-term forecast used in DESC's 2020 IRP beginning in 2022. DESC used a separate process to develop the short-term forecast for model years 2020 and 2021. This process was not reviewed as part of CRA's independent report.[7]

DESC defined three major customer classes in its long-term sales forecast: residential, commercial and industrial. Within each customer class, DESC further categorized customers based on their rate class, weather sensitivity, and building type. The result of this process is an equation that describes how the explanatory variables influence electricity sales or customer growth within each customer class, and to what degree. Various statistical tests are applied to ensure that no important explanatory variables have been excluded and that the resulting equations and estimated coefficients feature "goodness of fit" with the historical data.

Using the resulting equations, estimates of future electricity sales and customer growth for each class are generated based on forecasts of the same relevant macroeconomic drivers obtained from IHS Global Insight, Inc. Finally, the results for all classes are combined to develop a forecast of total sales and customer growth across the DESC system.

The sales and customer count forecasts that result from this process serve as the basis for the estimate of future peak energy demand. Peak demand for the residential and commercial classes was estimated on a per customer basis based on an historical analysis of demand during summer and winter peak hours. For the industrial classes, the peak demand forecast is based on the historic relationship between daily sales and demand during the summer and winter peak hour.

DESC made adjustments to the econometrically-derived energy and demand forecasts to account for the company's own use, transmission losses, and incremental DSM programs expected in the DESC service territory. A separate study of DSM potential and impacts was developed by ICF International and accepted by the Commission as part of Docket No. 2019-2-E. The results of the so-called "2019 Potential Study" serve as the inputs into the "Medium" view of DSM assumed in the Base case outlook for the 2020 IRP.

DESC developed high and low load growth scenarios that affected expected sales and peak demand growth over the forecast period. DESC also developed alternate High and Low DSM scenarios that were tested against the eight resource portfolios. Finally, DESC presented three views of electric vehicle ("EV") penetration to illustrate potential impacts of EV adoption on

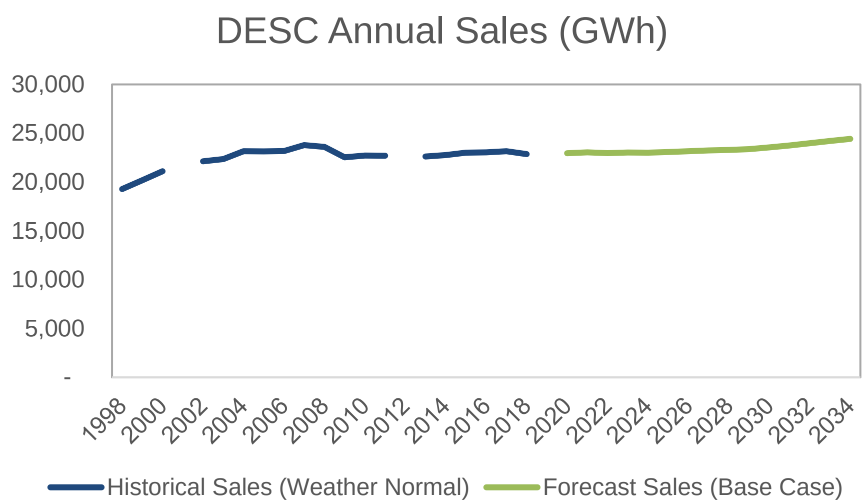
[7] Lynch, Joseph M., and Joseph Stricklin, "Energy Forecast Documentation Short Range and Long Range for 2020 Budget and Beyond"

customer loads. Incremental EV loads were not included in the peak requirements for the 2020 IRP, but will be included in future IRPs.[8]

5.4. Load Forecast in the 2020 IRP

Figure 1 illustrates the Base case sales forecast across all customers. This figure includes energy savings projected in the Medium DSM case, but excludes line losses.[9]

Figure 1: Annual Sales Forecast from the 2020 DESC IRP compared with Historical Sales



Annual sales are projected to grow at a Compound Annual Growth Rate ("CAGR") of 0.5% over the 2020-2034 period, as described in the 2020 IRP.[10] Sales are not projected to reach the historic maximum observed in 2008 until 2032. Projected sales growth is slower over the first ten years of the forecast due to the DSM programs described in the 2019 Potential Study. Once those programs achieve their full potential around 2030, the rate of growth increases in the final forecast years.

DESC forecasts peak demand for both the summer and winter seasons. Figure 2 compares forecast growth in firm summer peak demand from the 2020 IRP with historical values. Overall, summer peak demand is projected to grow at a CAGR of 0.7% over the 2020-2034 forecast, as described in the IRP[11]. DESC is projecting peak demand to grow at a faster rate than sales. This difference is driven primarily by the growth in the residential class, which tends to have peakier demand relative to the commercial and industrial classes.

[8] 2020 DESC IRP pg. 12-13

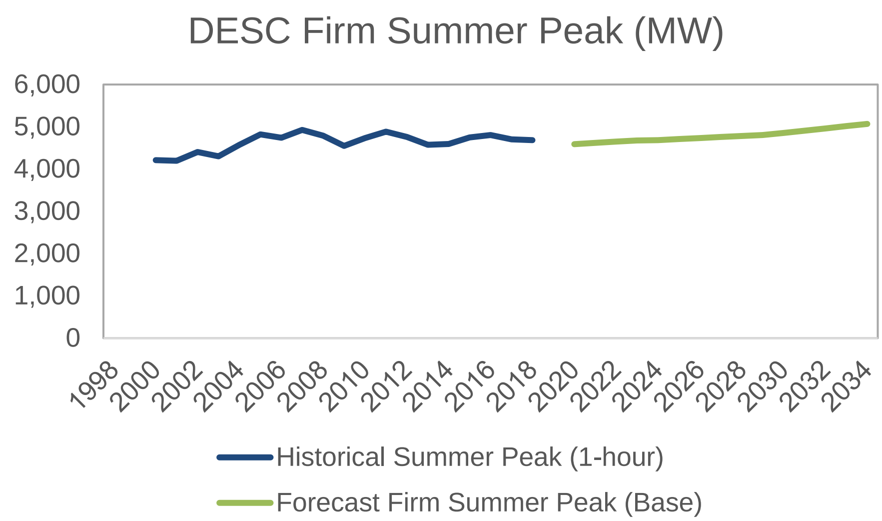
[9] DESC appropriately included line losses in the 2020 IRP forecast of energy demand, since the IRP must plan for energy requirements at the generator locations, not metered load. CRA has removed the line losses from the forecast in this figure to enable an accurate comparison with the historical data, because historical sales volumes are aggregated from readings at customer meters.

[10] 2020 DESC IRP pg. 9

[11] Ibid.

Peak summer loads are projected to grow more slowly over the first ten years of the forecast due to the impacts of DESC's DSM program. The increased growth rate in the final five years reflects the saturation of the measures included in the expanded programs. Summer peaks are not projected to reach the historic maximum observed in 2007 until 2031.

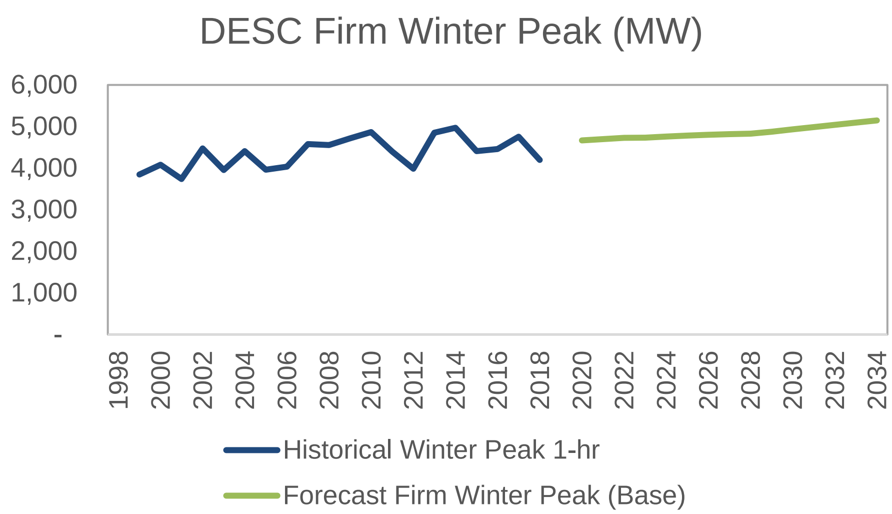
Figure 2: Comparison of Historical Firm Summer Peak Demand with the 2020 DESC IRP Forecast



DESC's forecast of firm winter peak demand also grows at a CAGR of 0.7% as described in the IRP.[12] Figure 3 compares the firm peak forecast from the 2020 IRP with the historical winter peaks on the DESC system. The forecast exceeds the historical peak observed in 2018 starting in 2021, because winter peaks are projected to grow quickly due to strong growth in the residential sector and penetration of electric heating in the DESC service territory.

[12] Ibid.

Figure 3: Comparison of Historical Firm Winter Peak Demand with the 2020 DESC IRP Forecast



5.4.1. Comparison of DESC Load Forecast with Regional Utilities

CRA compared the Base case load growth assumptions from DESC's 2020 IRP with those of regional utilities, summarized below in Table 1.

Table 1: Comparison of Load Growth Forecasts from Recent IRPs

State	Utility Name	Forecast Period	Peak Growth Rate	Energy Growth Rate
SC	Santee Cooper[13]	2018-2032	0.48% (S & W)	0.15%
NC	Duke Energy Carolinas[14]	2019-2033	1.03% (S Peak) 0.85% (W Peak)	0.86%
NC	Duke Energy Progress[15]	2019-2033	1.05% (S Peak) 0.94% (W Peak)	1.00%
TN	TVA[16]	2018-2038	0.30%	0.10%
GA	Georgia Power[17]	2019-2029	0.50%	0.70%
AL	Alabama Power[18]	2020-2034	-0.35%	-0.17%

13 http://www.energy.sc.gov/files/view/Santee%20Cooper_IRP_2018_FINAL.pdf

14 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de

15 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7f4b3176-95d8-425d-a36b-390e1e57a175

16 https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan

17 GA PSC Document #175473

18 https://www.alabamapower.com/content/dam/alabamapower/Our%20Company/How%20We%20Operate/Regulations/Integrated%20Resource%20Plan/IRP.pdf

FL	FPL[19]	2019-2028	1.15% (S Peak) 0.96% (W Peak)	0.62%
FL	Gulf Power[20]	2019-2028	-0.06% (S Peak) -0.11% (W Peak)	-0.12%
FL	TECO[21]	2019-2028	1.19% (S Peak) 1.26% (W Peak)	1.02%

DESC forecasts 0.5% average annual energy growth, a value well within the range assumed for load growth by regional utilities, which range from -0.2% per year in Alabama Power's most recent IRP to just over 1.0% growth per year at TECO. DESC's assumed peak load growth of 0.7% per year also falls well within the range of regional utilities. Again, Alabama power represents the bottom of the range at -0.4% per year, while TECO projects the fastest peak growth of nearly 1.3% per year.

DESC projects that peak demand will grow faster than energy demand. This relationship is also observed at the other South Carolina utility, Santee Cooper, and for most, but not all, regional utilities reviewed.

5.5. DESC Forecast by Major Customer Class

DESC defined three major customer classes for the purpose of forecasting sales and peak energy: residential, commercial and industrial. Within each customer class, DESC further categorized customers based on their rate class, weather sensitivity, and building type.

Separate regression models were specified for each of the defined sub-categories. Major variables in the sales forecast regression models included economic and demographic indicators, weather, and time-dependent events throughout the analysis period.

All models were estimated in the log-log form, which allows forecasting based on growth rates and the estimated coefficients on each variable to be interpreted as elasticities. Table 2 summarizes the regression models developed for the residential, commercial, and industrial customer classes for the 2020 DESC IRP.

Table 2: Summary of Regression Models Used by DESC to forecast R, C, and I Load

Class	Models Reviewed
Residential	Single Family Non-Space Heating Use Multi Family Non-Space Heating Use Mobile Home Non-Space Heating Use Single Family Space Heating Use Multi Family Space Heating Use Mobile Home Space Heating Use Residential Customer Count
Commercial	Small Commercial Use

19 https://www.fpl.com/company/pdf/10-year-site-plan.pdf

20 http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Gulf%20Power.pdf

21 http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Tampa%20Electric%20Company.pdf

	Medium Commercial Use Large Commercial Use Other Commercial Use Small Commercial Customer Count Medium Commercial Customer Count Large Commercial Customer Count Other Commercial Customer Count
Industrial	SIC 22 Textiles Use SIC 24 Lumber & Wood Use SIC 26 Paper Use SIC 28 Chemicals Use SIC 30 Rubber & Plastics Use SIC 32 Stone, Clay & Glass Use SIC 33 Primary Metal Use SIC 99 Non-Classifiable Use

DESC used coefficients from the regression models to estimate sales and customer growth using forecasts of economic and demographic variables obtained from IHS Global Insight, Inc. Forecasts for the price and weather variables were developed by DESC based on historical data.[22] Table 3 illustrates the growth rates for key economic variables underlying the 2020 IRP load forecast. The trend projection relied upon for the 2020 IRP is characterized by slow, steady economic growth with no major disruptions, such as substantial oil price shocks, major swings in policy, or unusually rapid increases in demand.[23]

Table 3: Annual Growth Rates for South Carolina Economic Variables[24]

Description	2020-2034 CAGR (%)
Population	0.85%
Real State Personal Income	2.34%
State Personal Income	4.65%
Manufacturing Employment	-0.39%
Industrial Production	1.48%
Households	1.30%

22 DESC response to CRA data request and interviews with Joseph M. Lynch

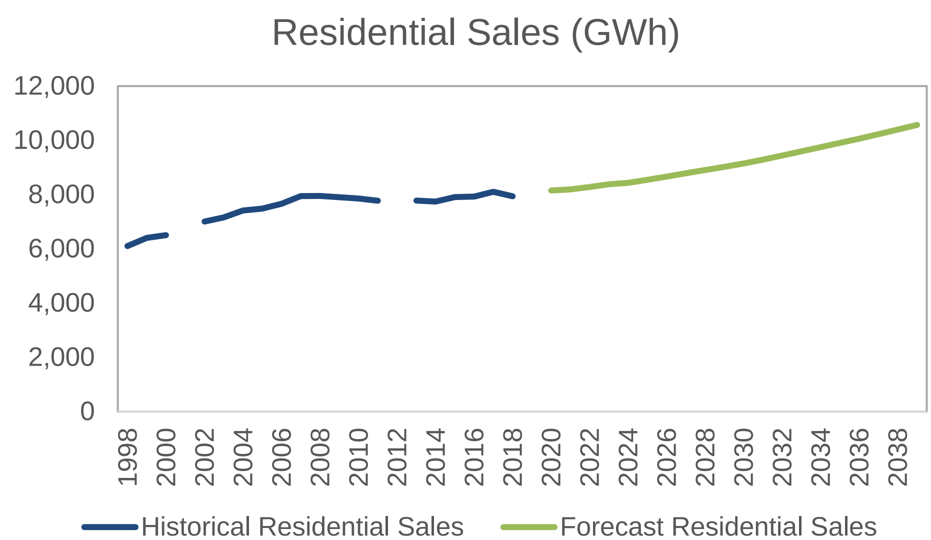
23 Lynch, Joseph M., and Joseph Stricklin, “Energy Forecast Documentation Short Range and Long Range for 2020 Budget and Beyond” pg. 11

24 DESC was unable to share the actual IHS forecast figures for all classes and years due to licensing limitations. CRA instead reviewed the forecast growth rates of select variable to review the reasonableness of economic variables.

5.5.1. Residential Load Forecast

The residential sales forecast, illustrated in Figure 4, was calculated based on forecasts of customer growth and average use per customer ("UPC"). The residential forecast includes six sub-categories as shown above in Table 2. Sub-categories for energy use were developed to distinguish between customers and uses that are more and less weather sensitive, and whether the housing type is single family, multifamily or mobile. DESC calculated the annual forecast of residential sales by multiplying the average UPC by the number of customers in each forecast year across each of the six sub-categories. DSM impacts from incremental residential efficiency programs were then subtracted from this forecast to achieve the final contribution of the residential class to the load forecast, pictured below.

Figure 4: Forecast and Historical Residential Sales from the 2020 IRP[25]



DESC Approach to Forecasting Residential Use Per Customer

UPC for the residential class was forecasted separately for heating and not-heating demand across single, multi, and mobile home customers. Average UPC in the residential class, pictured in Figure 5, represents the combination of these six sub-categories. The average residential UPC is projected to fall slightly then recover in the first ten years of the forecast due to incremental energy efficiency efforts included in the Medium DSM forecast. After these programs achieve their full potential in the 2030 timeframe, modest growth is observed in residential UPC.

All residential class sales forecast regressions included real per capita income, heating and cooling degree days and the GDP price deflator. In some models, other variables such as the time trend or 0/1 variables for specific years (i.e., recession or 2018) were included to control for the major economic or political events identified throughout the analysis period. These variables were included only for models when they were statistically significant.

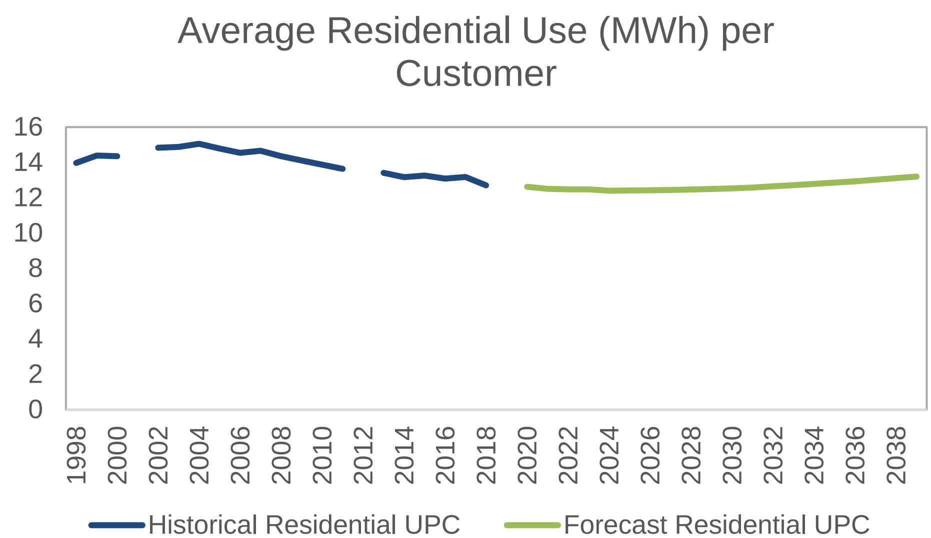
Real per capita income was used to control for the economic activity in the service territory, which is statistically significant at 99% confidence level for all residential customer groups. The estimated coefficient of this variable was positive for all models, as expected, indicating that

[25] Note that gaps in this historical series reflect missing data points.

energy consumption increases as the real income per capita increases. This could be explained by larger home sizes and more electronics being used in the wealthier households.

Residential customers' energy consumption is affected by outside temperature and space heating preferences. Therefore heating degree days ("HDD") and cooling degree days ("CDD") are appropriately included in the models to control for the impact of weather on customers' electricity consumption. The estimated coefficient on the HDD and CDD variables are positive, indicating that as cooling and heating loads increase, customers will demand additional electricity and vice versa.

Figure 5: Forecast and Historical Residential Use per Customer from the 2020 IRP

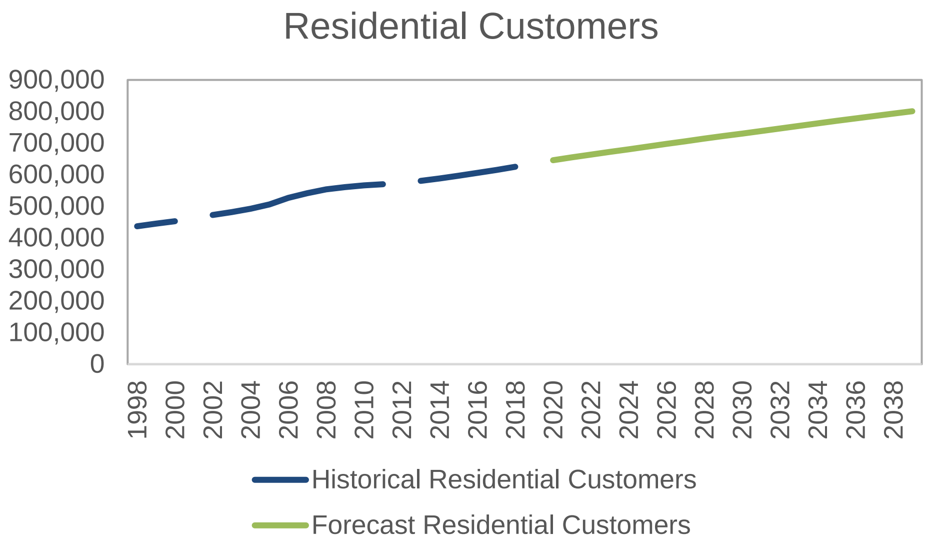


The regressions also include the GDP price deflator, which measures the changes in the prices of goods and services produced in the US. This variable is included to control for the price for goods and services in the economy throughout the analysis period. The estimated coefficient on this variable is negative, indicating that as households pay more for all goods and services, including electricity, the amount of electricity demanded is expected to decrease.

DESC Approach to Forecasting Residential Customer Growth

The rate of residential customer growth was also estimated through regression analysis. This forecast produced annual total residential customer growth rate which was apportioned to single, multi, and mobile homes. Figure 6 compares residential customer growth from the 2020 IRP forecast with historical growth in the DESC service territory. The 2020 IRP forecasted customer growth at a CAGR of 1.1%, which is modestly lower than the 1998-2018 growth rate of 1.2% per year.

Figure 6: Forecast and Historical Residential Customer Growth from the 2020 IRP

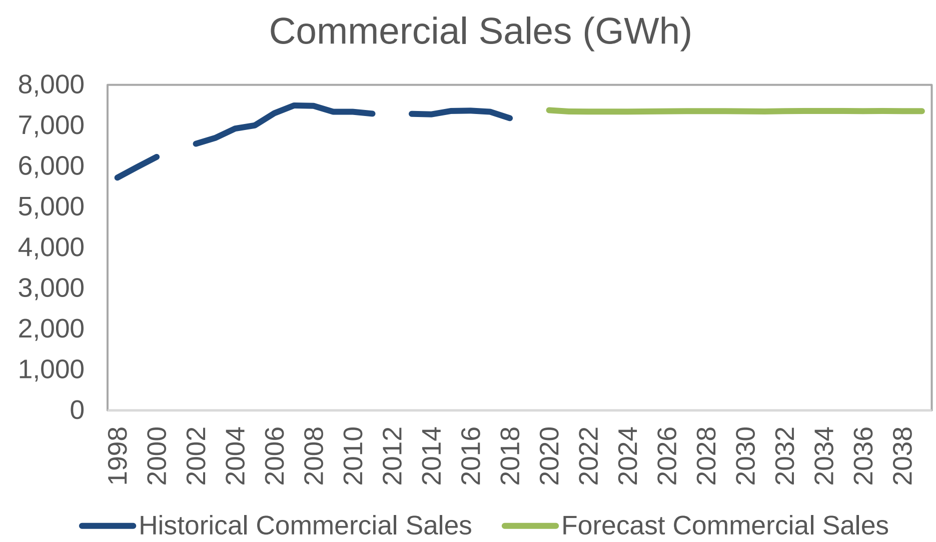


The key variables used to specify the residential customer count forecast model include the number of households, 0/1 variables to explain housing growth between 2006 and 2010, and a variable to control for recession in 2008. The estimated coefficient for the number of households variable is positive, indicating that growth in households correspond with growth in residential sector customers.

5.5.2. Commercial Load Forecast

The commercial sales forecast in the 2020 IRP was developed by estimating UPC and total customer growth for four sub-categories: small, medium, large, and other. Similar to the residential forecast, the average user per customer was multiplied by the number of customers in each sub-category. The impacts of the DESC DSM program were then subtracted from the sum of sales from each of the sub-categories, resulting in the final contribution of the commercial class to the 2020 load forecast, illustrated in Figure 7.

Figure 7: Forecast and Historical Commercial Sales from the 2020 IRP



DESC forecasted commercial sales to grow at a CAGR of 0.0%, which is lower than the 1998-2018 CAGR of 1.1%, but consistent with the trend in commercial sales growth over the past ten years. This flat outlook on sales reflects decreasing energy used in the class observed in the historical data, as well as the impact of DESC's DSM program.

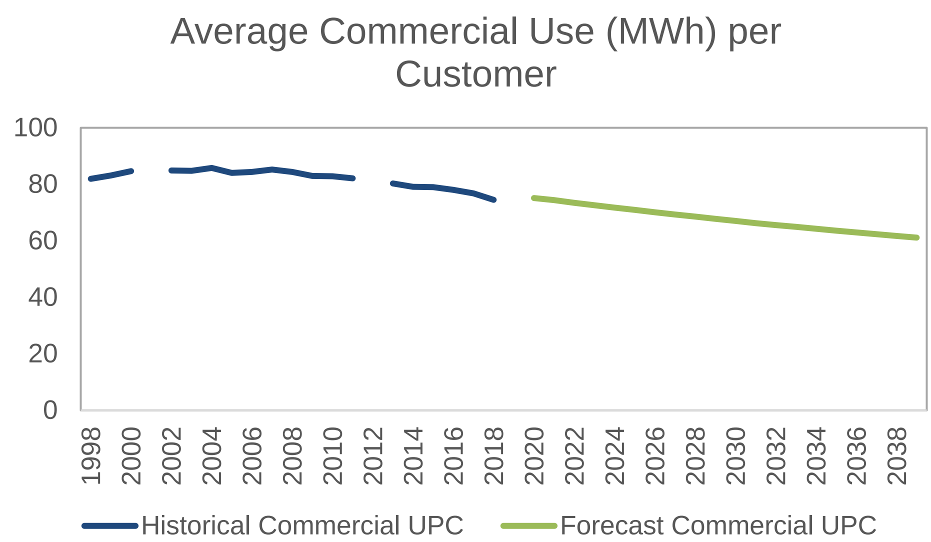
DESC Approach to Forecasting Commercial Use Per Customer

As described above, DESC forecasted sales per customer separately for four sub-categories in the commercial class: small, medium, large, and other. Figure 8 compares the average UPC from the 2020 IRP forecast with the historical values. In general, use per commercial customer is falling in the DESC IRP forecast in a trend that is consistent with historical values over the past ten years and which is further driven by energy efficiency programs included as part of DESC's DSM program.

For small, medium, and large commercial customers, the key explanatory variables were CDDs and electricity prices, in addition to a 0/1 variable to account for the recession recovery period and a time trend. The "other" commercial load model is specified with the average price for other commercial sub-categories, a time trend, and a 0/1 variable for recession recovery period.

The estimated coefficient on the price variable for each of the customer sales regression equations is negative and statistically significant, indicating that as the price of electricity rises, the amount demanded by commercial customers falls, as expected.

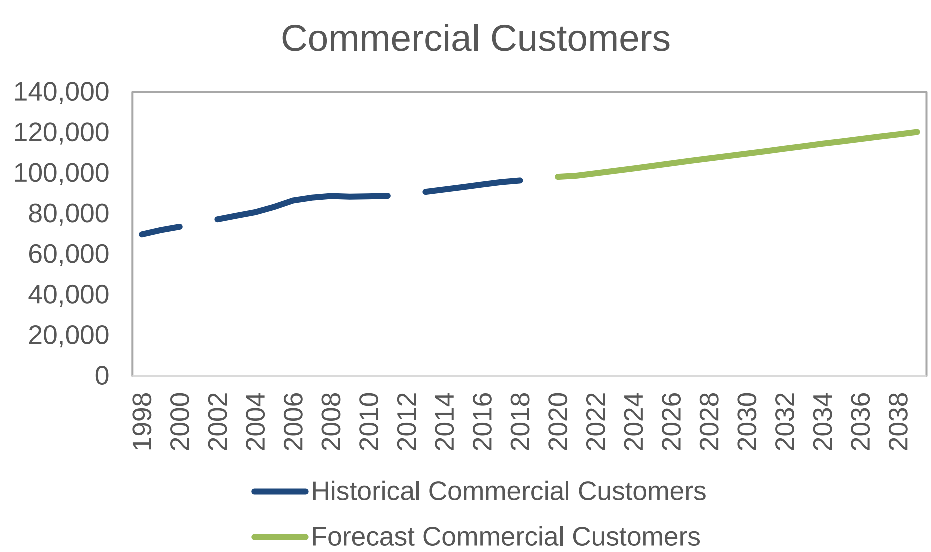
Figure 8: Forecast and Historical Commercial Use per Customer from the 2020 IRP



DESC Approach to Forecasting Commercial Customer Count

DESC forecasts customer growth for each of the four sub-categories separately. Figure 9 compares the forecast of commercial customer growth to the historical growth in this class. Commercial customers are forecast to grow at a CAGR of 1.1% in the 15-year forecast, which compares to a 1998-2018 historical CAGR of 1.6%.

Figure 9: Forecast and Historical Commercial Customer Growth from the 2020 IRP



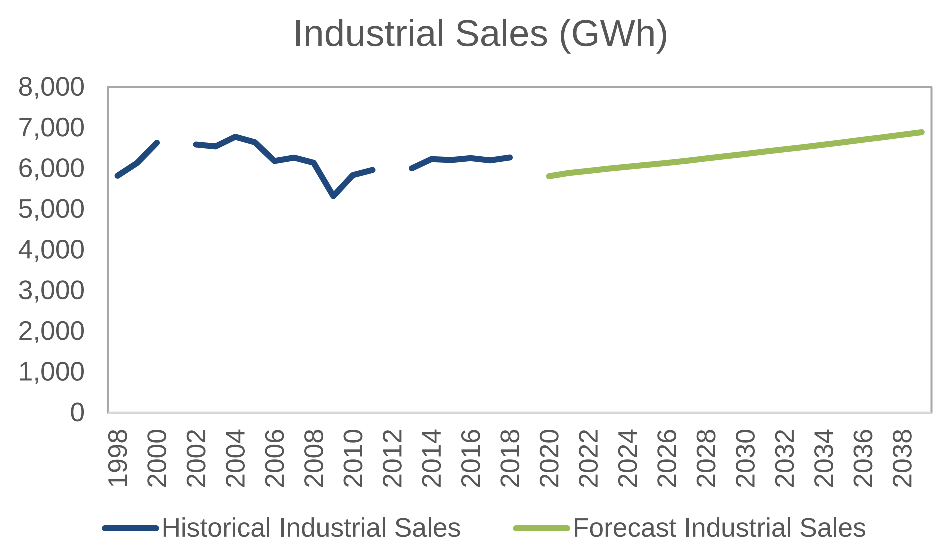
For small, medium and large commercial classes, the key variable used to forecast customer count was the number of households, reflecting the fact that commercial buildings would be more concentrated near more urban and population dense areas. Additional 0/1 variables were used to control for recovery from recessionary periods and shift the time trend in the small, medium and large commercial classes. For the other commercial classes, which mostly include overhead floodlights, private street lighting, shared lighting, and unmetered service, customer counts were forecasted using service area real income and a 0/1 variable to control for recessionary years.

5.5.3. Industrial Load Forecast

DESC forecasted growth in the industrial class across five sub-categories based on Standard Industrial Classification ("SIC") codes that are chosen to reflect the industrial mix in the DESC service territory. Industrial sales are forecast directly and driven primarily by the forecast of industrial production in the respective industries.

Figure 10 compares the forecast of industrial sales from the 2020 IRP with historical sales. DESC forecasts industrial sales growth at a CAGR of 0.9%, which is higher than the 1998-2018 CAGR of 0.4%, but consistent with the growth rate observed from 2010 onward. Further, the forecast stays within the range of historical observations through 2038.

Figure 10: Forecast and Historical Industrial Sales Growth from the 2020 IRP



Because industrial customers tend to be heterogeneous in their energy consumption, DESC forecasted load separately for different industrial groups in its service territory. DESC developed models for the following industrial classes: SIC 22 Textile, SIC 24 Lumber & Wood, SIC 26 Paper, SIC 28 Chemicals, SIC 30 Rubber & Plastics, SIC 32 Stone Clay & Glass, SIC 33 Primary Metal, and SIC 99 Non-classifiable.

Specifically, DESC forecasted sales in these categories using the forecast of industrial production for the SIC categories included in the relevant industrial sub-category. For SIC codes 22, 26, and 99 expert judgment was employed based on DESC's knowledge of specific customers.[26] This approach is reasonable and indicates that industrial demand for electricity increases as additional goods are manufactured. For SIC 99 group, the variable used to forecast load is miscellaneous industrial production and 0/1 variables for the years 2009 and 2018.

5.5.4. Peak Demand Forecasts

DESC built on the forecasts described above to develop winter and summer peak loads for the 2020 IRP. In all classes, the long-term sales or customer count forecasts were used to forecast the contribution to peak load based on analysis of customer sales data controlled for weather differences observed in each year.

Residential Sector Peak Forecast Review

In the residential sector, DESC forecasted seasonal peak demand by combining the forecast of customer growth, described above in section 5.5.1, with the estimated contribution of each customer to system demand in the peak summer and winter hour. Figure 11 and Figure 12 compare the IRP assumption for peak contribution in the year 2020 with the historical values in summer and winter, respectively. These forecast values include the impact of the Medium DSM program from the 2019 Potential Study.

In the summer, the 2020 IRP assumption of 3.3 kW per customer is well within the range observed in the 1998-2018 data. In the winter, the 2020 IRP assumption of 3.9 kW per customer is also well supported by historical observations from 1998-2018.

[26] Interviews with DESC experts Eric Bell, Joseph M. Lynch, and Joseph Stricklin.

Figure 11: Firm Summer Peak Demand per Residential Customer[27]

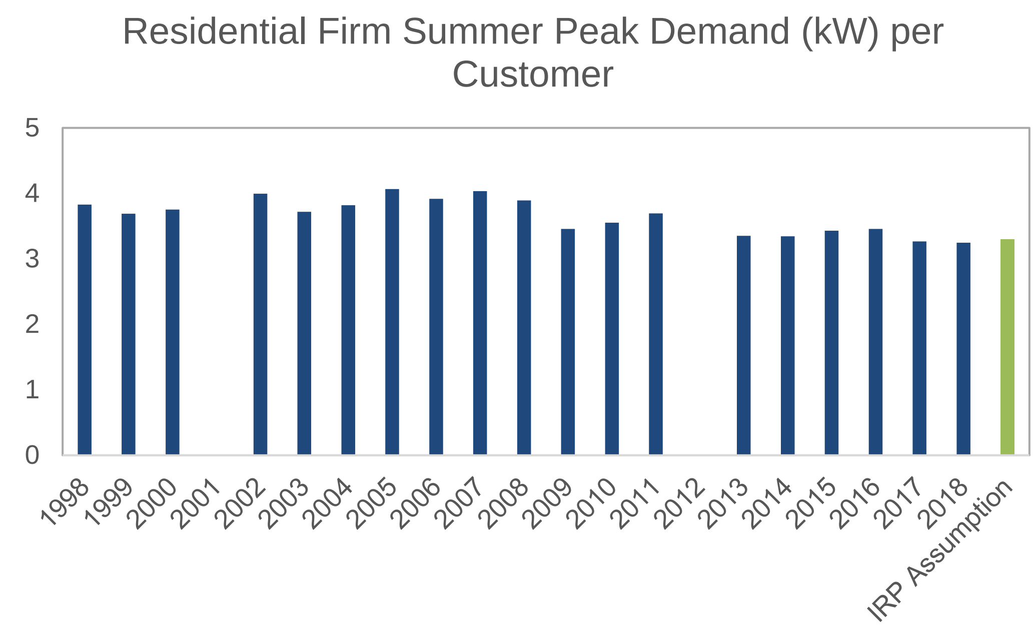
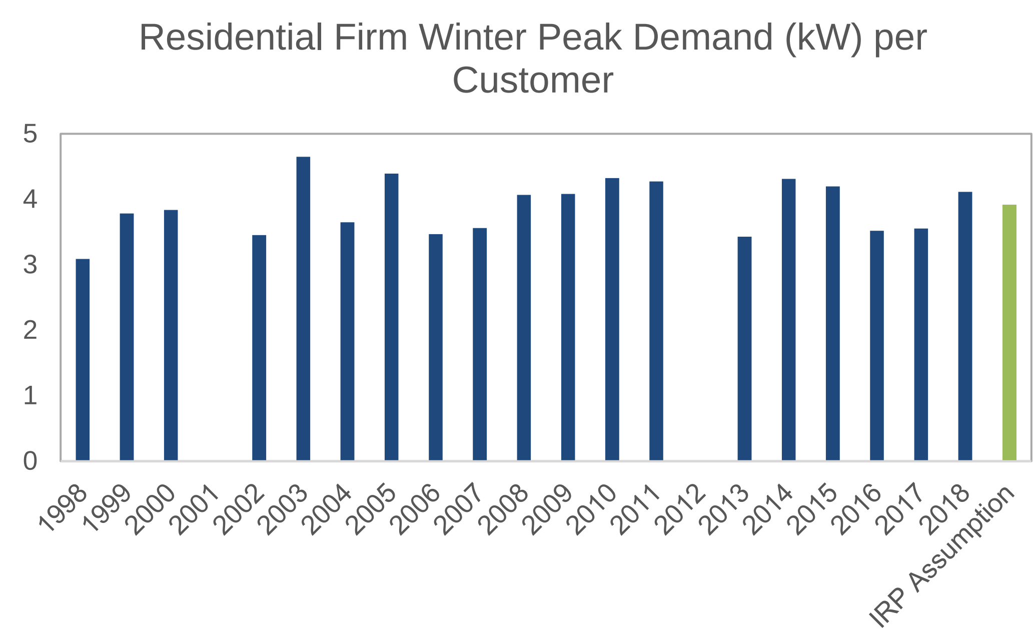


Figure 12: Firm Winter Peak Demand per Residential Customer



[27] These figures compare the values from the IRP forecast with the actual peak loads of the system, meaning variability from year to year in these figures includes demand impacts and weather. Note that DESC controlled for weather when developing their forecast of peak contribution by class.

Commercial Sector Peak Forecast Review

In the commercial sector, DESC forecasted seasonal peak demand by combining the forecast of customer growth, described above in section 5.5.2, with the estimated contribution of each customer to system demand in the peak summer and winter hour. Figure 13 and Figure 14 compare the per-customer peak contribution in the DESC 2020 IRP to the historic contribution of the commercial class to seasonal peaks in the summer and winter seasons, respectively. Note that the IRP value is inclusive of incremental efficiency in this class consistent with the Medium DSM forecast.

The 2020 summer forecast of 15.8 kW per commercial customer is consistent with the observations from 2013-2018 and lower than observations from previous years. This is consistent with the reduction in commercial use per customer illustrated above in Figure 8. In the winter, the 2020 estimated peak contribution per commercial customer is estimated to be 13.8 kW, which is consistent with observations throughout the 1998-2018 period.

Figure 13: Summer Peak Demand per Commercial Customer

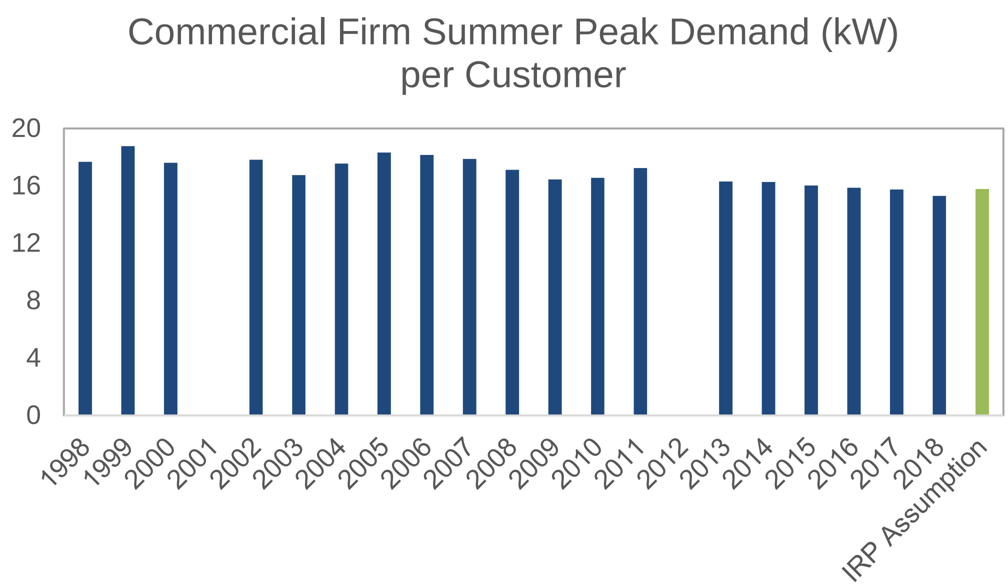
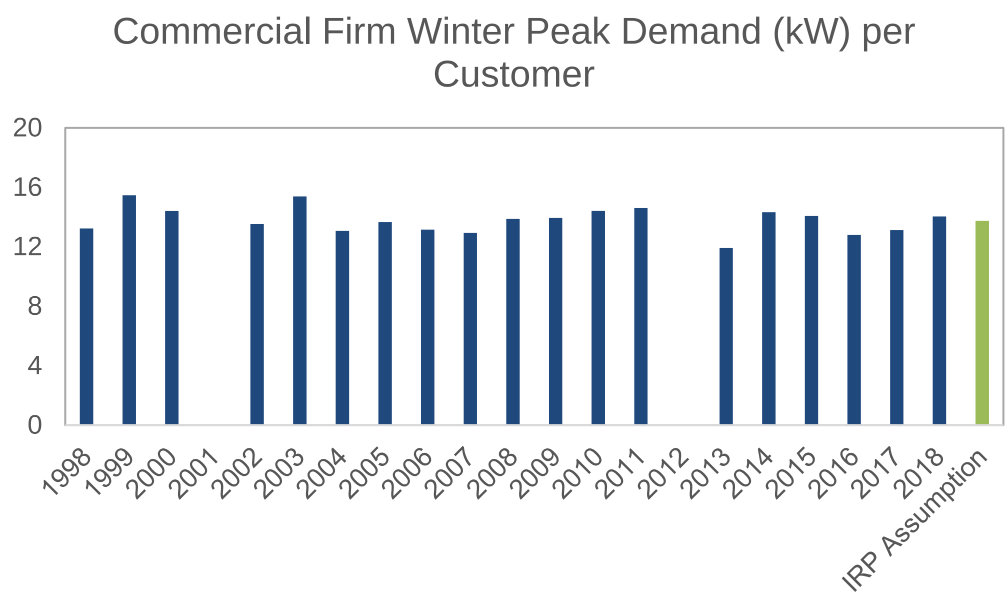


Figure 14: Winter Peak Demand per Commercial Customer



Industrial Sector Peak Forecast Review

In the industrial sector, DESC forecasted seasonal peak demand by evaluating the relationship between demand in the peak hour of the winter and summer season to the average daily industrial sales in those seasons from the historical data. This relationship between kW and KWh was then applied to the sales forecast described above in section 5.5.3. Figure 15 and Figure 16 compare the peak contribution of the industrial class in 2020 to the historical values for summer and winter respectively. The forecast values are inclusive of savings forecast in the Medium DSM forecast.

The summer peak contribution of 0.9 kW of peak demand per kWh of average daily sales is consistent with the historical relationship observed since 2011 and lower than the values for prior years. The winter peak contribution of 0.8 kW of peak demand per kWh of average daily sales is similar to the summer forecast in that it tracks closely with observations through 2011, but is somewhat lower than values in years 1998-2010.

Figure 15: Summer Peak Industrial Demand per kWh Consumed

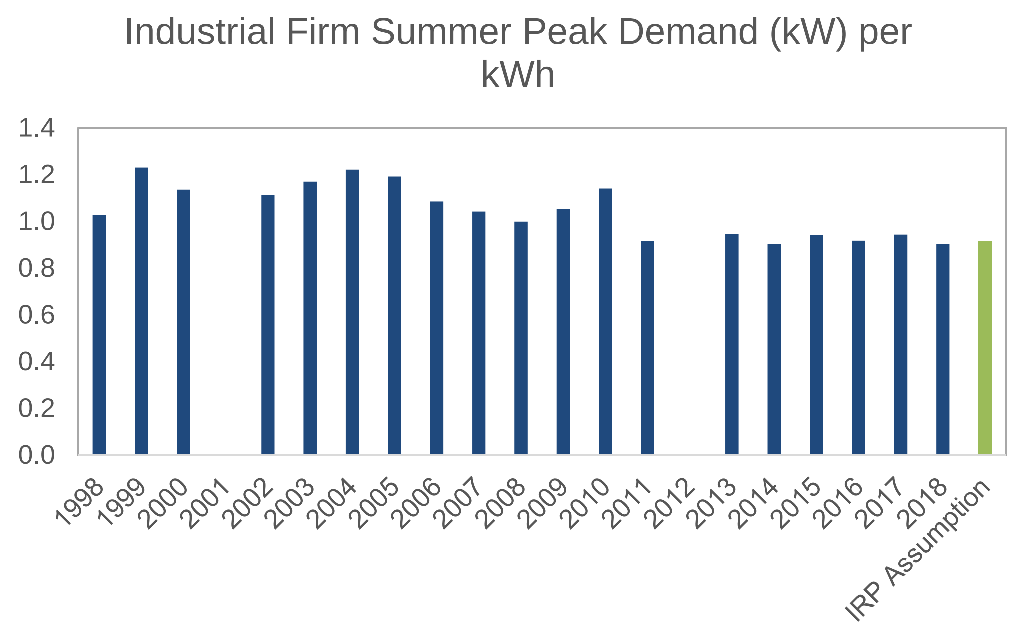
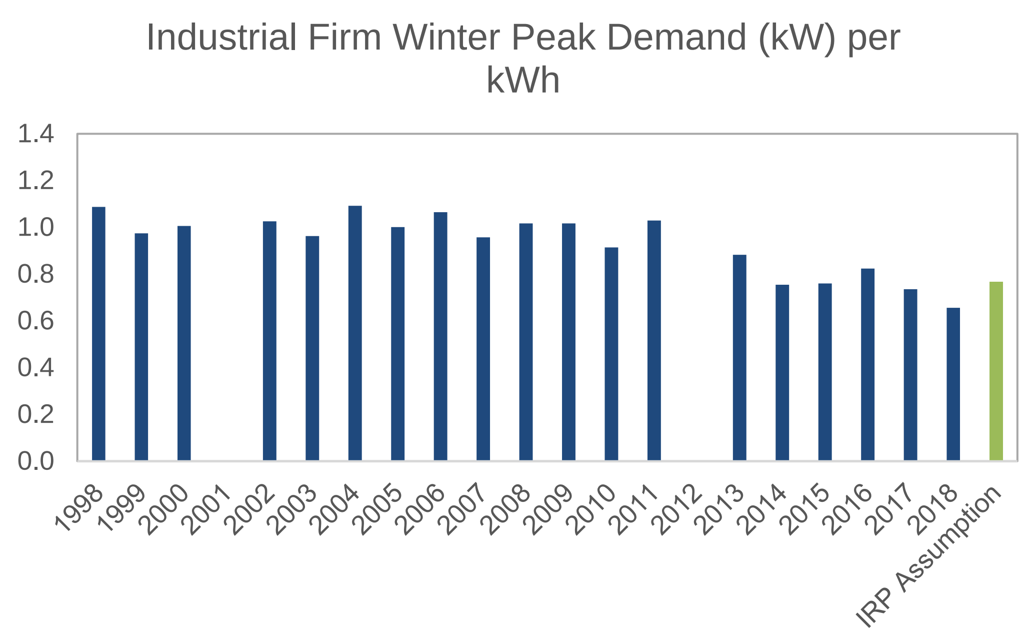


Figure 16: Winter Peak Industrial Demand per kWh Consumed



5.6. Reasonableness of the Load Forecasting Methodology and Approach

CRA's review of the load forecasts relative to historical data demonstrates that the sales and peak hour load projections by customer group reflect the levels and trends observed in the historical data. CRA also evaluated each of the models described in Table 2 above for reasonableness and determined that the equations for these customer classes use explanatory variables that are shown to be significant. As part of this review, CRA confirmed that the explanatory variables in the regression equations and their coefficients were reasonable and had the expected impacts on the dependent variables (e.g., that residential customer growth increases due to household growth and that as more households are added, more customers are added).

CRA also reviewed the detailed statistical outputs from each of the load forecasting models to confirm that the models are properly specified and have reasonable goodness of fit. The following section summarizes the details of this technical review.

5.6.1. Statistical Test Review

CRA reviewed the output of various statistical tests conducted by DESC to check the accuracy and validate the model fit, autocorrelation, and multicollinearity. The following tests were reviewed:

- The "R-squared," which is the percentage of the dependent variable variation that a linear model explains with the included independent variables. In other words, R-squared tells how well the data fit the regression model. Although there is not a specific cutoff value for a "good" R-squared statistic, generally a larger R-squared statistic indicates a better fit for the model.
- The Durbin-Watson statistic, which is used to determine whether there is autocorrelation in the residuals of the estimated regressions.[28]
- The root mean squared error ("RMSE"), which is the square root of the variance of the residuals. While R-squared is a relative measure of fit, RMSE is an absolute measure of fit. RMSE can be interpreted as the standard deviation of the unexplained variance. Similar to the R-squared statistic, there is not a specific threshold for the RMSE statistic. However, lower values of RMSE indicate a better fit.

Residential Class Statistical Test Review

Table 4 contains the post estimation statistics for the residential sales models used in the 2020 IRP. The residential class regressions have reasonable R-squared statistics, suggesting that the selected models are a good fit. In almost all regression models there is no autocorrelation detected. The exception was the "Mobile Home Non-Space Heating" model that was estimated using a lagged dependent variable (i.e., lagged energy sales) to correct for autocorrelation. In sum, all these test statistics suggest that the regression models employed for residential sales forecast are reasonable.

[28] The Durbin-Watson statistic does not represent a pass-fail test but instead is used to compare a set of regressions describing the same dependent variable (i.e. different models estimating residential UPC). DESC tested different model specifications for each subcategory before finalizing the models used for the 2020 load forecast. All the models used in the long-term load forecast for the 2020 IRP were tested for autocorrelation and corrected for where found.

Table 4. Residential Sector Post Estimation Statistics

Customer Class	R-squared	Detected Autocorrelation	RMSE
Single Family Non-Space Heating	0.8615	N	0.02746
Multi Family Non-Space Heating	0.5645	N	0.03549
Mobile Home Non-Space Heating	0.7873	Y	0.05053
Single Family Space Heating	0.9378	N	0.02314
Multi Family Space Heating	0.9064	N	0.02899
Mobile Home Space Heating	0.7608	N	0.03333

Table 5 contains the post estimation statistics for the residential customer count model. The residential customer count regression has a reasonable R-squared statistic suggesting that the model has good fit. In addition, no autocorrelation was detected in the model. These test statistics suggest that the regression model employed for the residential customer count forecast is reasonable.

Table 5. Residential Sector Customers Post Estimation Statistics

Customer Class	R-squared	Detected Autocorrelation	RMSE
Residential Customer Count	0.9997	N	0.00355

Commercial Class Statistical Test Review

Table 6 contains the post estimation statistics for the commercial sales per customer models. The R-squared for each of the models is reasonably high, which indicates that the specified models are good fit. In almost all models, autocorrelation was detected. Therefore, all of these models are estimated with the lagged dependent variable. These test statistics suggest that the regression model employed for the residential customer count forecast is reasonable.

Table 6. Commercial Sector Sales Post Estimation Statistics

Customer Class	R-squared	Detected Autocorrelation	RMSE
Small	0.8286	Y	0.01786
Medium	0.9031	Y	0.01257
Large	0.6577	Y	0.03361
Other	0.7404	Y	0.13059

Table 7 contains the post estimation statistics for the commercial customer count model. Post estimation statistics, including the R-squared for each commercial customer group suggest that the model fit is reasonable. For small, medium and large commercial customer group models, the lagged dependent variable was used due to autocorrelation.

Table 7: Commercial Sector Customers Post Estimation Statistics

Customer Class	R-squared	Detected Autocorrelation	RMSE
Small	0.9713	Y	0.00879
Medium	0.7950	Y	0.00756
Large	0.9477	Y	0.03611
Other	0.9294	N	0.06161

Industrial Class Statistical Test Review

For each of the SICs in this group, a model was developed and elasticities estimated, which were then applied to corresponding industrial growth production indices. Table 8 contains the post estimation statistics for the industrial class sales models. The R-squared statistic for each of the models is reasonably high, which indicates that the specified models are a good fit. Autocorrelation is corrected for where detected.

Table 8: Industrial Sector Sales Post Estimation Statistics[29]

Customer Class	R-squared	Detected Autocorrelation	RMSE
SIC 22 - Textiles	0.9636	Y	0.10664
SIC 28 - Chemicals	0.9241	Y	0.05247
SIC 30 – Rubber & Plastics	0.9279	N	0.02490
SIC 32 – Stone, Clay & Glass	0.9690	Y	0.05454
SIC 33 – Primary Metal	0.7886	N	0.03750

5.6.2. Reasonableness of Load Scenario Development

As described in the preceding sections, CRA has reviewed the major components of the Base case load forecast and found them to be reasonable. DESC describes the Base case as the “most-likely” view, and also modeled load scenarios as part of the 2020 IRP built upon four views of DSM penetration, as described in Table 9, to test impact on system costs. Note that all scenarios exhibit impacts to seasonal peaks and annual sales.

Table 9: Load Scenarios Modeled in the 2020 IRP

Load Scenario	Description
Low DSM Case	DSM grows to 0.4% of retail sales by 2024, equivalent to DSM program levels prior to the 2019 Potential Study
Medium DSM Case	DSM grows to 0.7% of retail sales by 2024, equivalent to expanded program scenario from the 2019 Potential Study
High DSM Case	DSM grows to 1% of retail sales by 2024, extrapolated from the expanded program results of 2019 Potential Study based on consultation with study authors ICF
SBA DSM Case[30]	DSM grows to 1.25% of retail sales by 2024, provided by SBA and not supported by measures from the 2019 Potential Study

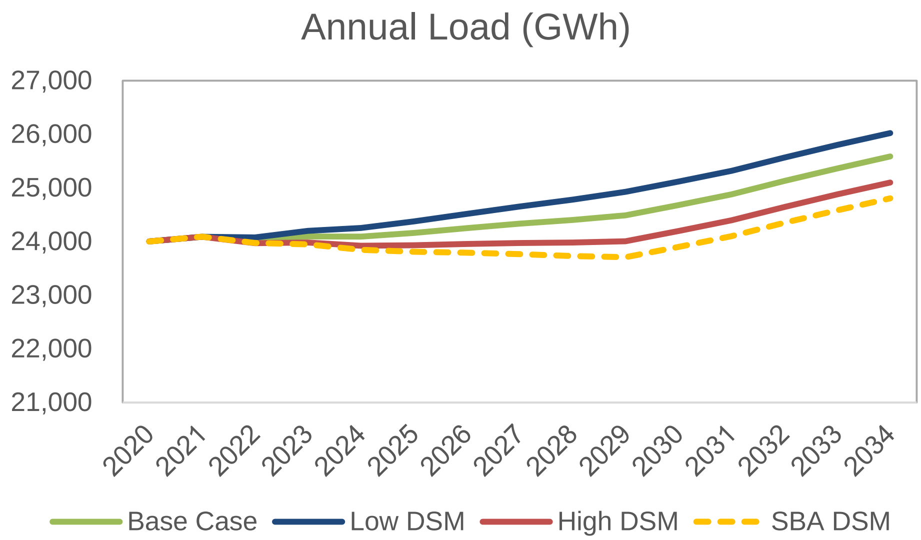
Figure 17 illustrates the range of sales forecasts modeled in the 2020 IRP, with all figures including energy efficiency impacts. Sales in the Base case grow at a CAGR of 0.5% from 2020-2034. The Low DSM scenario exhibits faster growth at a CAGR of 0.6% due to the loss of incremental efficiency measures. The High DSM scenario demonstrates the impact of

[29] Regression models for SIC codes 24 Lumber & Wood, 26 Paper, and 99 Non-Classifiable were developed by DESC but the forecast for these customers groups includes expert judgment. Therefore CRA does not review the statistical outputs of these models.

[30] The South Caroline Solar Business Alliance (“SBA”) provided an alternate view of DSM penetration as part of the SBA portfolios that were run by DESC as part of the 2020 IRP.

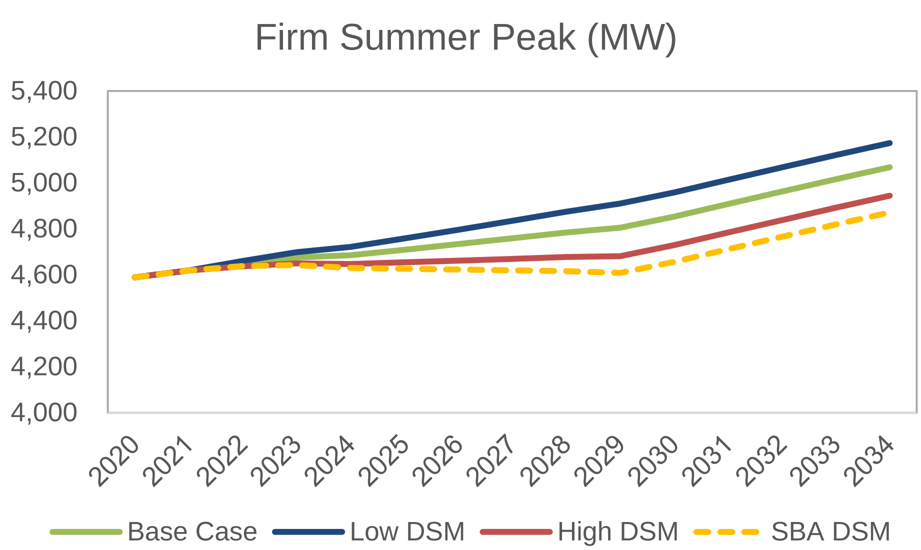
incremental efficiency efforts and lowers the growth rate to 0.3% annually. Finally, the SBA scenario grows slowest, with an overall CAGR of 0.2%.

Figure 17: DESC Sales Forecast Scenarios from the 2020 IRP



The summer peak demand forecast naturally follows a similar trend to the sales forecast as seen in Figure 18. The Low DSM scenario tends to result in increased rates of peak growth, which rise to 0.9% annually up from 0.7% per year in the Base case. The High DSM scenario, on the other hand, tends to reduce peak growth, which falls to 0.5% per year over the forecast period. Again, the SBA scenario exhibits the slowest overall growth, with summer peaks expected to grow at 0.4% annually. The summer peak forecasts correctly reflect the DSM assumptions provided to CRA and demonstrate a reasonable range of likely outcomes for the portfolio modeling.

Figure 18: Firm Summer Peak Scenarios from the 2020 IRP



The impact on peak values is also consistently applied across seasons. Figure 19 illustrates firm winter peak values under the four load scenarios. The Low DSM scenario grows at 0.9% per year, up from 0.7% per year in the Base case. Slower growth is seen in the High DSM scenario at 0.5% per year, and in the SBA scenario at 0.4% per year. Note that firm peaks in 2020 are lower in the High DSM case than in the other three scenarios. This is due to an assumed incremental winter demand response ("DR") program. The winter peak forecasts correctly reflect the DSM assumptions provided to CRA and provide a reasonable range of likely outcomes for the portfolio modeling.

Figure 19: Firm Winter Peak Scenarios from the 2020 IRP

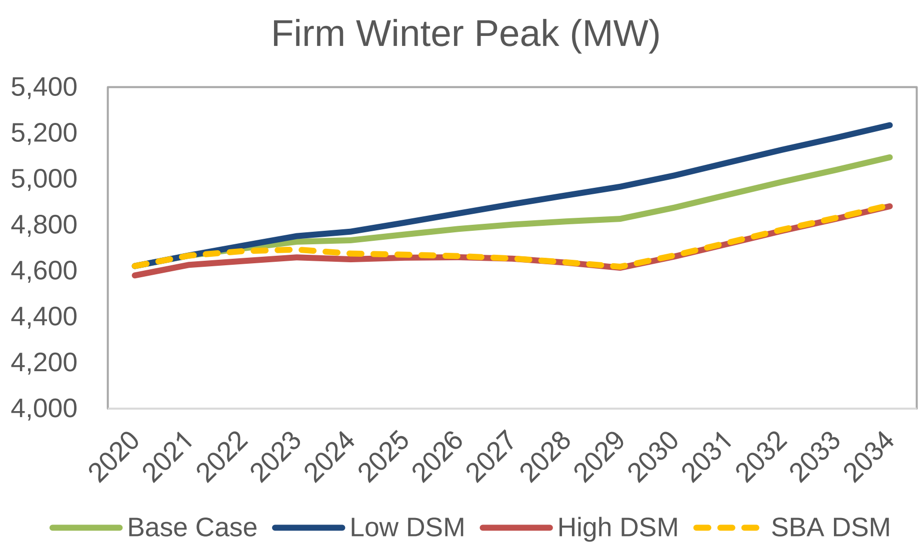


Table 10 below illustrates the load sensitivities considered by regional utilities in their most recent IRPs. DESC considered a peak growth range that, at the low end, was 0.3% per year lower than the Base case and, at the high end, was up 0.2% per year compared to the Base case. CRA notes that many regional utilities considered no load sensitivities as part of their IRPs.[31] Compared with regional utilities that did consider alternate load views, the range included in DESC's 2020 IRP is relatively narrow. CRA views the range of load scenarios considered by DESC in the 2020 IRP to be reasonable, but notes that future IRPs could be enhanced by considering lower probability load outcomes that range further from the Base case outlook.

[31] CRA also reviewed the main IRP documents of Duke Energy Progress, Alabama Power, FPL, and Gulf Power and did not find reference to load scenarios but did not check all appendices and supporting documents.

Table 10: Comparison of Load Scenarios Considered in Recent Utility IRPS

State	Utility Name	Peak Growth (Low Case)	Δ from Base (Low Case)	Peak Growth (High Case)	Δ from Base (High Case)
SC	Santee Cooper[32]	Modeled - Not Public	Modeled - Not Public	Modeled - Not Public	Modeled - Not Public
NC	Duke Energy Carolinas[33]	0.20%	-0.83%	2.00%	+0.97%
TN	TVA[34]	-0.70%	-1.00%	1.70%	+1.4%
GA	Georgia Power[35]	Modeled - Not Public	Modeled - Not Public	Modeled - Not Public	Modeled - Not Public
FL	TECO[36]	0.84%	-0.42%	1.68%	+0.42%

32 http://www.energy.sc.gov/files/view/Santee%20Cooper_IRP_2018_FINAL.pdf
33 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de
34 https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan
35 GA PSC Document #175473
36 http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Tampa%20Electric%20Company.pdf

6. Reserve Margin

6.1. Key Findings

CRA reviewed DESC's reserve margin policy and associated analyses and has concluded the following:

- DESC has demonstrated that summer and winter demand-side risk are significantly different from each other and that seasonal planning reserve margin targets should reflect such differences. This is reasonable, consistent with many other utilities in the region, and in line with broader industry trends.
- DESC has demonstrated that peak events, especially in the winter, are characterized by large load spikes with limited duration. Thus, it is reasonable to consider different base and peaking planning targets, but DESC should consider more robustly supporting its criteria to define the base reserve margin in the future.
- DESC's overall evaluation of demand-side risk is based on sound econometric principles and industry-standard practice for performing load uncertainty analysis.
- DESC's overall evaluation of supply-side risk is reasonable, but additional rationale for the selection of the right supply-side risk threshold would improve confidence in the policy standard.
- DESC's loss of load expectation ("LOLE") study was based on an industry-standard metric of 0.1 days per year or 1 day in ten years, and the application of both supply-side risk and demand-side load shapes in the study were reasonable. In future LOLE study reviews, DESC may consider evaluating hourly granularity and including weather risk to further test the robustness of its reserve margin policy.

6.2. Scope of Review

CRA has reviewed DESC's reserve margin policy and supporting documents and analyses, including the "2018 Reserve Margin Study," the "Loss of Load Expectation Study," and the testimony of Joseph M. Lynch, Ph.D. regarding both reports.[37] CRA also reviewed the "Operating Manual for the VACAR Reserve Sharing Agreement" and conducted phone interviews with DESC resource planning and load forecasting experts regarding the reserve margin policy and associated analyses.

CRA's review has focused on the reasonableness of the following elements of DESC's reserve margin policy:

- The approach to identify separate winter and summer reserve margins and separate base and peaking reserve margins;
- The approach to evaluate and incorporate demand-side risk, supply-side risk, and VACAR reserve sharing obligations in the development of the reserve margin policy; and
- The approach to conduct an LOLE study and its role in supporting the reserve margin policy.

[37] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

6.3. DESC Approach to Calculating Planning Reserve Margins

For planning purposes, DESC has established reserve margin targets for both the summer and winter seasons and for what are categorized as the base and peaking time periods. As a dual-peaking load serving entity with weather profiles that differ by season, DESC specifically plans to meet reserve margins for both winter and summer periods. Given hourly load profiles that can spike considerably for short durations of time, especially in the winter, DESC has also chosen to separate the reserve margin needed for such peak periods from the "base" margin needed during the large majority of hours across a season or year.[38] An overview of the reserve margin policy is presented in Table 11, while the remainder of this section defines the reserve margin targets further and reviews DESC's methodology for defining the targets.

Table 11: DESC Reserve Margin Policy Summary[39]

DESC's Reserve Margin Policy		
	Summer	Winter
Base Reserves	12%	14%
Peaking Reserves	14%	21%
Increment for Peaking	2%	7%

6.3.1. Core Analysis

The foundation of DESC's reserve margin policy is an analysis that estimates the reserves needed above the seasonal peak load forecasts in three distinct categories:

- Reserves required for the VACAR reserve sharing requirement;
- The potential for peak demand to rise above and beyond the planning forecast due to unexpected weather; and
- The potential supply-side risk associated with unexpected plant outages.

The core analysis is designed to evaluate the total reserves that may be needed and hence is associated with the peaking reserves standard.

VACAR Reserve Sharing

DESC is a member of the VACAR Reserve Sharing Group along with other utilities within NERC's VACAR region: Santee Cooper, Duke Carolinas, Duke Progress, and Dominion Energy Virginia. Membership in the group allows for the utilities to access contingency reserves from outside of their native systems in the event of an emergency, and DESC is obligated to carry approximately 200 MW of reserve capacity to fulfill its commitment.[40] Therefore, in

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[38] Note that the IRP portfolio analysis is performed against the Base Reserves target and DESC affirms in its 2020 IRP that "statements about reserve margin are generally addressing Base Reserve criteria." See DESC 2020 IRP, p. 38.

[39] DESC 2020 IRP, p. 38. Note that the Commission accepted these reserve margins in Order No. 2018-322(A), but DESC performed additional analysis in DOCKET NO. 2019-2-E to evaluate more weather-driven risk for load.

[40] The "Operating Manual for the VACAR Reserve Sharing Agreement" contains specific information regarding reserves protocols and the calculation of each member's contribution requirement. The system-wide contingency reserve commitment is based on the largest contingency across member utilities, while DESC's contribution to that requirement is calculated based on a formula that evaluates DESC's share of total system peak load and the ratio of DESC's largest resource to the sum of all utilities' largest resources in the system.

establishing reserve margin targets, DESC assumes 200 MW is required above peak load projections for both the summer and winter seasons.

Demand-side Risk

In order to quantify risk associated with peak demand rising above and beyond the planning forecast, DESC performed econometric analysis to evaluate future load risk based on historical data since 1991. This econometric analysis identified the historical relationship between HDDs and CDDs and peak load and used the historical relationships to estimate future peak load uncertainty around the current load forecast. More specifically, the peak load uncertainty analysis was most concerned with estimating the potential peak load should the most extreme weather since 1991 occur. DESC performed econometric analysis to evaluate three types of statistical equations to fit the historical data:

- A quadratic equation for all HDDs and CDDs in the season (DESC's traditional approach in prior studies):
- A quadratic equation using a restricted number of days (100 hottest and 100 coldest days); and
- A linear equation using a restricted number of days.

DESC found that all three approaches generally resulted in similar results and concluded that the traditional approach, with the quadratic equation for all days, was valid. This resulted in a quantification of demand risk of 245 MW in the summer and 556 MW in the winter, as shown in Table 12.

Table 12: Peak Demand Risk by Econometric Equation Specification[41]

	Quadratic equation for all days	Quadratic equation with restricted days	Linear equation with restricted days
Summer	**245 MW**	252 MW	292 MW
Winter	**556 MW**	617 MW	509 MW

Supply-side Risk

In order to quantify risk associated with unexpected plant outages, DESC assessed historical plant outage data over the 2010-2017 time period. The data set covering this time period included a sample of over 700 days of observations for each season. As part of this assessment, DESC developed an estimate of the total MW forced out at various percentiles across the historical data set. This is summarized in Table 13. For example, for 50% of the summer hours over the historical data set, 106 MW or less were forced out. For 90% of the winter hours over the historical data set, 520 MW or less were forced out.

[41] DESC 2018 Reserve Margin Study, p. 8-9.

Table 13: MW Forced Out by Percentile and Season[42]

MW Forced Out by Percentile						
Percentile	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Summer	**106**	**152**	**234**	**385**	**618**	**1,402**
Winter	**121**	**165**	**223**	**373**	**520**	**1,552**

In developing the reserve margin target, DESC selected the 70th percentile, resulting in a need to cover supply-side risk of 234 MW in the summer season and 223 MW in the winter season.

Overall Peak Reserve Requirement

DESC combined the requirements associated with VACAR reserve sharing, demand-side risk, and supply-side risk to arrive at a total reserve MW need of 679 MW in the summer and 979 MW in the winter. These numbers translate into approximately 14% and 20% of the summer and winter peak load expectations, respectively. This is shown in Table 14. Given closeness to DESC's existing reserve margin policy of 14% and 21% for the two seasons, it was concluded that the existing policy was acceptable for use in the IRP.

Table 14: Peak Reserve Margin Summary[43]

Reserve Margin for Summer and Winter Peak Periods		
	Summer	**Winter**
VACAR Operating	**200**	**200**
Demand-Side Risk	**245**	**556**
Supply-Side Risk	**234**	**223**
Total Reserve MW	**679**	**979**
Normal Peak Demand	**4763**	**4852**
Reserve Margin %	**14.3%**	**20.2%**
Reserve Margin Policy	**14%**	**21%**

Base Reserve Requirement Need

DESC concluded that extreme weather events can result in system peaks that are significantly higher than expected forecasts, but generally short-lived. As a result, an analysis was performed to identify an alternative "base" reserve margin that would be sufficient to meet load and cover scheduled and un-scheduled outages for the large majority of the days in the year. Using the historical data discussed above, DESC evaluated the capacity need for each day from 2010 through 2017 for the winter and summer seasons by summing the peak load, forced and unforced outage capacity, and reserves required for the VACAR sharing agreement.

For each year, DESC then evaluated the reserve margin that would be needed to cover between 95 and 97 percent of the days. This would represent approximately all days but the top

[42] DESC 2018 Reserve Margin Study, p. 10.

[43] DESC 2018 Reserve Margin Study, p. 12.

five or ten peak days per season,[44] which for planning purposes could be separately covered by limited-duration peaking resources.[45] Under such a construct, DESC determined that a summer reserve margin between 12% and 14% and a winter reserve margin between 13% and 17% would be sufficient to meet between 95 and 97 percent of all daily peak days. As a result, the current base reserve margin policy of 12% for the summer months and 14% for the winter months was deemed to be reasonable.

6.4. DESC Approach for Loss of Load Expectation Study

DESC performed an LOLE study in response to questions raised in the 2018 Fuel Docket.[46] The goal of DESC's study was to identify a relationship between the LOLE index, represented as the likelihood of DESC's system being unable to serve load, and the system's reserve margin. The industry standard LOLE index is 0.1, representing an acceptable expectation that load will not be able to be met for 1 day in 10 years. The LOLE analysis incorporates both a load evaluation and a forced outage evaluation, followed by a simulation that combines the two.

Load Evaluation

DESC developed normalized load data sets using historical system load data from 2004-2018 under two methodologies:

- The "peak" method was used to adjust the historical load shapes to all align with the projected summer and winter peaks for 2019. This method holds the 2019 peak constant and shifts the other hours to produce hourly load profiles in accordance with those observed over the last fifteen years.
- The "energy" method was used to adjust the historical load shapes based on the projected 2019 energy to peak ratio. This method results in different peak outcomes for the data set, but preserves the integrity of the historical hourly load profiles.

Forced Outage Evaluation

DESC used the same historical 2010-2017 data from the reserve margin analysis described above to calculate an average historical forced outage rate for each unit in the fleet. The analysis deployed a "convolution algorithm" to combine individual binomial distributions for each resource's forced outage rate to create a capacity outage probability table ("COPT") which quantifies how many MWs are likely to be forced out on any given day. For example, as noted in DESC's report appendix, according to the historical analysis, the probability of 100 MW or more being forced out at any given point in time is 48%, while the probability of 900 MW or more being forced out at any given point in time is only 1.35%.[47]

LOLE Simulation

Using daily peak loads from the hourly load shaping exercise described above along with the COPT for forced outage probabilities, DESC performed a simulation to assess the likelihood of

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[44] See DESC 2018 Reserve Margin Study, p. 14 for additional description.

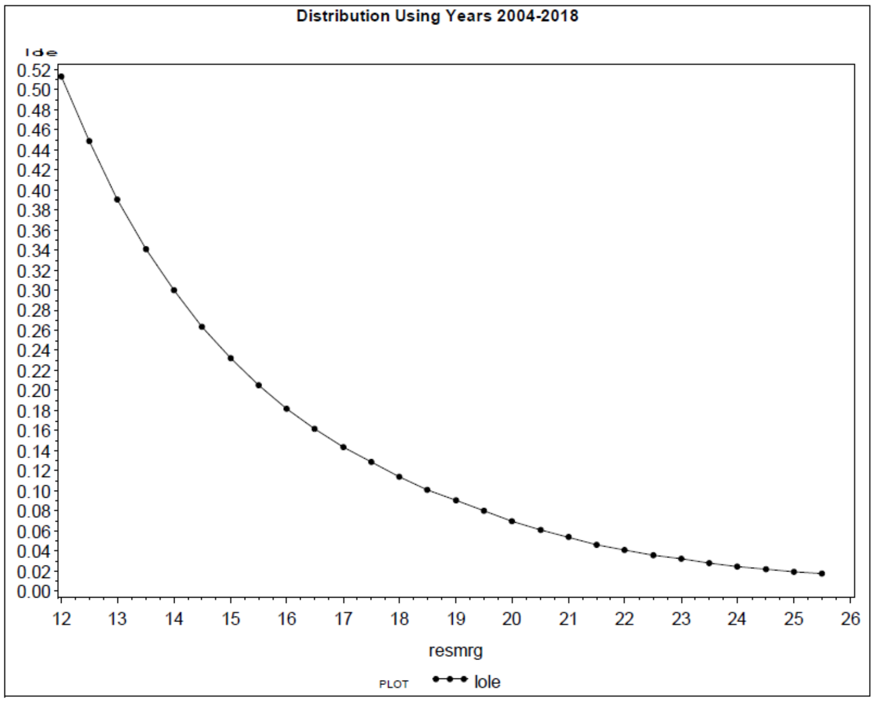
[45] As per a CRA interview with Joe Lynch, the peaks on the top five or ten days per season are assumed to be better covered by specific, short-duration peaking resources such as demand response measures.

[46] While this study was not relied upon in the development of DESC's reserve margin policy, it provides a relevant benchmark against certain industry standards.

[47] DESC LOLE Study, Appendix Table 2, p. 12.

daily demand being greater than supply. This was done across a variety of reserve margins ranging from 12% to 25% at 0.5% increments[48] and across all fifteen years of historical load shape data. An average of the resulting relationship between the DESC system's reserve margin (x-axis) and projected LOLE metric (y-axis) is shown in Figure 20 for the "peak" load shaping method. DESC concluded that a reserve margin of 18.5% would be needed to achieve an LOLE at the industry standard of 0.1 in the "peak" load shaping method. With the "average" load shaping method, the required reserve margin was calculated to be 18.1%

Figure 20: LOLE Outcomes across Reserve Margin Range – "Peak" Load Shaping Method[49]



48 Note that to achieve the reserve margin range, the whole system's capacity was scaled up and down, holding the daily load shapes constant (Source: Phone interview with Joe Lynch).

49 DESC LOLE Study, p. 5.

6.5. Reasonableness of DESC Approach for Seasonal Reserve Margins and Base and Peaking Reserve Margins

DESC's reserve margin policy is multi-faceted, with different targets by season and for the base and peaking time periods. The following reviews the reasonableness of this approach in the context of standards set by other peer utilities.

6.5.1. Reserve Margin Target Comparison with Other Peer Utilities in SERC

One way to assess the overall reasonableness of the reserve margin approach is to compare DESC's targets with other peer utilities in the SERC region, particularly those that are not part of a larger regional Independent System Operator like PJM or MISO.

It is increasingly common for utilities in SERC to examine both summer and winter reserve margins. In a review of nine recent IRP filings across SERC, four filings included separate reserve values for summer and winter seasons (TVA, Santee Cooper, Georgia Power, and Alabama Power). Three filings used a single reserve requirement value but explicitly calculated reserves in both summer and winter (Duke Energy Progress, Duke Energy Carolinas, and FPL). Two filings reported a summer planning reserve margin value and did not explicitly mention or appear to test winter reserve requirements (Gulf Power, TECO). It is likely that the trend of reporting separate summer and winter reserve requirements and testing across both seasons will continue, as solar generation becomes an increasingly larger portion of utility portfolios. A summary of the reserve margin targets for these peer utilities is provided in Table 15.

DESC's summer peaking reserve requirement of 14% is lower than the 17.3% average reported by these nine utilities. DESC's winter peaking reserve requirement of 21% is slightly higher than the 19.5% average reported by the seven utilities which explicitly evaluated winter reserves. In general, summer values across the sampled utility filings were within a tighter range than winter values, which ranged from 12% (Santee Cooper) to 26% (Georgia & Alabama Power).

Table 15: Peer Utility Reserve Margin Targets

State	Utility	IRP Release	RM Target	Notes
SC	Santee Cooper[50]	2018	15% Summer, 12% Winter	
NC	Duke Energy Carolinas[51]	2019	17%	Applies to both seasons.
NC	Duke Energy Progress[52]	2019	17%	Applies to both seasons.
TN	TVA[53]	2019	17% Summer, 25% Winter	Dual peaking system. New target for 2019, 2015 used 15% for entire year.
GA	Georgia Power[54]	2019	16.25% Summer, 26% Winter	System-wide, long-term values. Slightly lower near-term values (2020-2022). Prior IRP in 2016 used summer PRM only.
AL	Alabama Power[55]			
FL	FPL[56]	2019	20%	Applies to both seasons.
FL	Gulf Power[57]	2019	16.25%	Applies to summer, no mention of winter requirement.
FL	TECO[58]	2019	20%	Applies to summer, no mention of winter requirement.

6.5.2. Reasonableness of DESC approach of developing separate Summer and Winter reserve requirements

DESC has demonstrated that summer and winter demand-side risk are significantly different from each other and that seasonal planning reserve margin targets should reflect such differences. As noted above, many peer utilities in the region are also differentiating between the two seasons, reflecting a trend in this direction. It is likely that seasonal planning will become more important as intermittent resources with different operating profiles across seasons and time of day become more prevalent in the market. Thus, DESC's approach to develop separate seasonal targets is reasonable.

50 http://www.energy.sc.gov/files/view/Santee%20Cooper_IRP_2018_FINAL.pdf

51 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de

52 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7f4b3176-95d8-425d-a36b-390e1e57a175

53 https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan

54 GA PSC Document #175473

55 https://www.alabamapower.com/content/dam/alabamapower/Our%20Company/How%20We%20Operate/Regulations/Integrated%20Resource%20Plan/IRP.pdf

56 https://www.fpl.com/company/pdf/10-year-site-plan.pdf

57 http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Gulf%20Power.pdf

58 http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Tampa%20Electric%20Company.pdf

6.5.3. Reasonableness of DESC Approach to Splitting Base and Peaking Components of Seasonal Reserve Requirements

DESC's analysis has demonstrated that peak events, especially in the winter, are characterized by large load spikes with limited duration. Thus, for planning purposes it is reasonable to consider different planning targets that can be met by different resource types. DESC's reserve margin analysis, particularly the highly quantitative review of the statistical likelihood of covering all daily peaks, is helpful in identifying how infrequently capacity needs are likely to be greater than the base planning target.

However, DESC may consider more robustly supporting the criteria which was established to define the base planning reserve margin with a more specific rationale in future reviews of the planning policy. DESC has concluded that its base reserve margin target alone will be sufficient to meet load (inclusive of VACAR reserve sharing requirements and forced and unforced outages) for between 95% and 97% of all days throughout the year. While this is a reasonable conclusion, more detail on the availability, cost profiles, and characteristics of the "peaking" resources that are part of the portfolio and expected to be available when needed during the remaining 3% to 5% of days would be helpful in justifying the separate target. Example "peaking only" resources might include:

- An interruptible demand response program with a limited number of hours across a season or year when it can be called upon;
- Short-term seasonal bilateral capacity purchases;
- A fossil-fired peaker unit (including one with oil fuel backup) that may have run hours restrictions due to air emissions permitting or other economic reasons; or
- A storage resource with limited duration to cover peak events and limits on cycling frequency to reduce maintenance costs and preserve warranty protections, such as a 4-hour battery.

DESC may also consider performing portfolio analysis against the full peaking reserve requirement in its future IRP in order to test whether such "short-duration" resources are a cost-effective part of the portfolio, subject to other system and portfolio design constraints. The 2020 IRP assumed that resources like demand response programs and other short-term winter peaking resources or purchases would meet this need, and a more complete review of the economics of such resources or further explanation on how they benefit the system would be supportive of such an approach.

6.6. Reasonableness of DESC Approach for Evaluating Demand-Side Risk

DESC's evaluation of demand-side risk is based on sound econometric principles and industry-standard practice for performing load uncertainty analysis. DESC evaluated historical load observations over a significant period of time (over 25 years of history) and tested the relationship between load and weather across three different statistical model constructs. All three load models were developed through a reasonable econometric approach, and the conclusions were based on appropriate statistical methodologies. All model specifications arrive at similar conclusions, and DESC's selection of model and the resulting demand-side risk planning requirement were both reasonable. Given the conclusion that winter weather-driven demand-side risk is more significant than weather-driven risk in the summer, it was reasonable to estimate different risk profiles by season, and DESC applied the risk metrics appropriately to the final reserve margin requirement calculations. As noted in the LOLE discussion below, DESC may consider integrating such demand-side risk in future statistical analyses of overall loss of load risk and evaluating the risk at a more granular, hourly level.

6.7. Reasonableness of DESC Approach for Evaluating Supply-Side Risk

DESC performed a substantial review of historical fleet operating and outage data over an eight-year period to assess the frequency of forced outages on the system. As part of this review, nearly 1,500 data points were developed, with over 700 days of data for each of the winter and summer seasons. DESC identified similar supply-side risk profiles across both seasons and selected a level of supply-side risk for its reserve margin policy that covers 70% of the expected hours.

While DESC has represented that the 70% target was vetted by internal experts, including operations managers, additional rationale for this standard based on historical analysis, other industry standards, or specific anecdotal operator experience would be helpful for future policy evaluations. For example:

- The remaining 30% of the days with supply-side outage risk higher than the target may have historically been concentrated in times when load is far from peak conditions, minimizing the overall loss of load risk;
- The duration of large outages may be small, meaning that the 30% daily risk is significantly lower on an hourly basis.
- In the event of large plant outage events, especially those of short duration, DESC may be able to call upon reserves from outside its territory through the VACAR reserve sharing agreement, mitigating the supply-side "tail risk" that may be present in the top 30% of days.[59]

While DESC's historical evaluation of its existing fleet is reasonable for the development of its current reserve margin policy, as its system evolves over time, DESC may wish to consider how a generation profile with additional intermittent solar might perform in the future. Historical data on solar performance may be currently limited, but weather data may be available to reasonably assess solar output uncertainty. DESC has performed an analysis of solar resources' contribution to peak, which is helpful in evaluating system reliability, but the IRP evaluates a long future planning horizon and future analysis might consider whether the reserve margin policy should change over time if additional intermittent resources enter the system.

Finally, DESC may consider evolving towards an evaluation framework that includes hourly granularity of supply-side risk analysis rather than its current daily structure. Such an approach may be helpful in refining the supply-side outage probability threshold and better represent a system with more intermittent resources.

[59] It is important to note that the reserve sharing arrangement is for emergency events, and by agreement DESC can only rely on reserves from the VACAR sharing agreement for 12 hours or until the end of the day, whichever is longer. Therefore, the arrangement should not be considered a reliable backup resource, but its presence could be used to support the rationale for why DESC does not need to select a supply-side risk metric that covers the full range of all potential outage risk outcomes.

6.8. Reasonableness of DESC approach for quantifying VACAR operating requirements in RM requirement

DESC has demonstrated that membership in the VACAR Reserve Sharing Group requires the utility to maintain additional reserves above those needed to cover system load. Thus, incorporating the 200 MW requirement[60] as part of the reserve margin policy is reasonable.

6.9. Reasonableness of DESC LOLE Study and application as a method for confirming findings of RM Analysis

DESC's approach of performing an LOLE study in order to compare the outcomes with its pre-established reserve margin policy was reasonable. The study was based on an industry-standard LOLE metric of 0.1 days per year or 1 day in ten years, and DESC's applications of both supply-side risk and demand-side load shapes were reasonable. The approach to develop the COPT from individual binomial distributions of forced outage rate for each plant in the fleet was statistically reasonable, and the development of different daily load shapes based on historical data was sound. However, DESC may consider future enhancements to its approach to provide alternative LOLE calculations that may account for additional system risks and uncertainties. Such options are outlined in more detail below.

Load Risk

DESC concluded that peak load in the LOLE analysis should not be varied based on weather uncertainty and noted in its report that, "The LOLE index may be useful as a measure of the average risk on a system over the entire year but it does not address the risk from peak demands that spike up under severe weather conditions."[61] To support this point, DESC conducted an experiment where an increase in peak winter load by 500 MW would only need 195 MW of additional capacity to bring the system back within an acceptable LOLE level of 0.1. This is because the extra capacity mitigates risk on all days, not just the peak day.

Across the industry, LOLE study techniques and models vary, but many do evaluate weather-driven load risk, above and beyond the peak and energy load shaping methods that were deployed. DESC might consider future incorporation of the load risk in an LOLE study to assess the overall impacts to the results beyond the experiment that was conducted. The experiment reasonably concluded that the nature of DESC's short-duration winter peaks make the system's load profile unique, but further quantification of the implications of load risk within an LOLE study, including in an hourly framework (see more below), could be useful in the future.[62]

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[60] CRA has reviewed the "Operating Manual for the VACAR Reserve Sharing Agreement" and summary spreadsheets provided by DESC that show the calculation of its contingency reserve contribution requirement for each of the last four years (2017 through 2020). Over that time period, DESC's requirement has ranged between 193 MW and 199 MW.

[61] DESC LOLE Report, p. 9

[62] Note that load uncertainty is a core part of DESC's reserve margin policy analysis that arrived at a 21% peak winter reserve margin target, and inclusion in the LOLE study would likely raise the required reserve margin for the winter above the 18.1%-18.5% range produced in the study.

Daily vs. Hourly Granularity

DESC performed its LOLE study with daily granularity, simulating peak days and daily outage probabilities. This approach is reasonable because the LOLE metric is based on a daily standard. Nevertheless, other studies in the industry perform the analysis on an hourly basis, interpreting the standard as 24 hours over 10 years or 2.4 hours per year. Given the nature of DESC's load profile, with short-duration winter peak events driving considerable loss of load risk, an hourly LOLE approach may be warranted in future testing. This approach would implicitly capture the "spikiness" of the load profiles and partially address the concern regarding weather uncertainty noted above. Thus, an hourly analysis may provide additional perspective to the overall reserve margin analysis.

VACAR Reserve Sharing Agreement

DESC did not incorporate the 200 MW VACAR reserve sharing agreement requirement in its LOLE analysis. If included on the load side, additional requirements would increase the reserve margin required to achieve the 0.1 LOLE standard. However, additional supply that may be available from regional utilities in the event of system emergencies[63] could mitigate the supply-side risk, reducing the reserve margin required to achieve the 0.1 LOLE standard. As a result of these offsetting factors, DESC's decision to focus the study on its native system and not incorporate the arrangement's requirements and benefits in the LOLE study is reasonable. Future testing of the impacts of including the reserve sharing agreement, however, may be instructive.

[63] It is important to note that by agreement DESC can only rely on reserves from the VACAR sharing agreement for 12 hours or until the end of the day, whichever is longer. Furthermore, weather is highly correlated among VACAR members, meaning that extreme weather-driven load spikes impacting DESC would likely be impacting neighboring utilities at the same time, reducing the likelihood that reserves would be available.

7. Portfolio Analysis

7.1. Key Findings

CRA reviewed DESC's portfolio modeling assumptions and associated analyses and has concluded the following:

- DESC's overall approach used standard industry tools and was comprehensive in its scope. In the future, DESC may consider enhancing its tools and capabilities to ensure that the widest possible range of options is evaluated.
    - PROSYM was a reasonable tool for the 2020 IRP, but future IRPs may consider incorporating another tool that allows for least cost optimization of capacity expansion.
    - DESC has demonstrated that the IRP evaluated 94 different scenario-portfolio combinations. The portfolios evaluated a wide range of resource options, including retirement of existing resources. In the future, DESC may consider a broader assessment of existing resource options with fuller support for specific retirement dates evaluated.
    - DESC considered a reasonable set of new resource options as relevant replacement technologies and developed a number of scenarios and portfolios that used assumptions provided by the South Carolina SBA.
- The IRP assumptions for new resource options were generally reasonable and consistent with current market trends and standard practice in the industry.
    - The capital and operating costs assumed by DESC for new generation supply were generally reasonable and consistent with assumptions from similar IRPs in the industry; however treatment of the investment tax credit ("ITC") was conservative for new DESC-owned solar resources added in 2026. In addition, fixed O&M costs for solar and batteries owned by DESC were understated.
    - Unit performance assumptions for thermal, renewable, and storage resources were reasonable and consistent with assumptions from similar IRPs in the industry. DESC's characterization of flexible solar resources was reasonable, and DESC did not disadvantage solar supply as a resource type by allowing curtailment.
    - The cost and terms of Power Purchase Agreements ("PPAs") modeled in the IRP were reasonable and consistent with the 2019 NREL Document relied upon by DESC.[64]
- DESC evaluated its portfolios across a range of key uncertainties, including fuel costs, carbon pressure, and customer demand. DESC's selection of scenario variables was reasonable, and input ranges reflect an appropriate band of uncertainty. However, future IRPs may consider evaluating a wider range of load.
- DESC has demonstrated that the DSM resources identified in the 2019 Potential Study are included in the 2020 IRP portfolios and result in the appropriate amount of energy and peak savings.

[64] NREL (National Renewable Energy Laboratory). 2019. 2019 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2019.

- DESC has demonstrated that the input assumptions described in the IRP and supporting documents are reflected in the estimated system costs. The resource plans modeled in PROSYM match the descriptions in the IRP, and the model outputs reflect reasonable and appropriate calculations.

7.2. Scope of Review

CRA's independent report focuses on validating the inputs to the PROSYM dispatch model, evaluating the tools and methods used to dispatch the DESC portfolio and develop cost projections, and reviewing the range of outlooks and resource plans considered by DESC in the 2020 IRP.

To that end, CRA has:

- Received and reviewed DESC's revenue requirement spreadsheets, which combine PROSYM output with capital cost calculations to produce total system costs, along with a wide range of data items and reports provided by DESC staff in native format supporting these calculations. The files were primarily Microsoft Excel format, containing modeling assumptions describing the load and DSM assumptions in each scenario, unit fuel and operating costs used in dispatch modeling, the cost outputs of the PROSYM simulations, and fixed cost assumptions used to estimate revenue requirements.
- Reviewed DESC's "green-book" assumptions sheets that provide resource characteristics by technology type, as well as the levelized cost calculation used by DESC to develop PPA costs for solar and battery storage.
- Reviewed DESC's Expansion Plan files, which detail existing supply, new resources for each resource plan, DSM, and load over the study period, and demonstrate how reserve margins are maintained in PROSYM over time as resources are added and retired from the system. CRA audited these inputs and the calculation of summer and winter reserve margin to ensure that each plan met the requirements and was identical to the plan described in the IRP.
- Reviewed the revenue requirement spreadsheets, which combine PROSYM outputs with capital cost calculations to produce total system costs for each plan. CRA has reviewed annual unit output, including fuel costs, fuel burn and generation, for select resource plans under various scenarios to ensure consistency with input assumptions described in the IRP document.
- Conducted multiple interviews with DESC experts Eric Bell, James Neely, Sheryl Shelton, and Therese Griffin regarding different aspects of the DSM forecast, dispatch modeling, and revenue requirement inputs and calculations. CRA reviewed documents produced by these experts describing the approach and assumptions used for modeling solar technology in the 2020 IRP including "The Capacity Benefits of Solar QFs 2018 Study" and the supporting testimony of Joseph M. Lynch, Ph.D. regarding that report.[65] CRA reviewed the "The Capacity Benefit of Solar QFs 2019 Study" and supporting responses of James Neely as part of Docket No. 2019-226-E.[66] CRA also reviewed the "2019 Potential Study"

[65] The testimony and both supporting reports were filed in SCPSC Docket #2019-2-E.

[66] Response 2-15 from James Neely, Dominion Energy South Carolina Inc, Office of Regulatory Staff's Second and Continuing Request for Production of Books, Records, and Other Information. Docket No. 2019-226-E

developed by ICF International and accepted by the Commission as part of Docket No. 2019-2-E.

7.3. Overview of DESC's IRP Analysis Approach

DESC's IRP analysis included the following major steps:

1. Establishment of the current portfolio of resources and demand for benchmarking purposes;
2. Projection of future demand requirements (See Chapter 5) and resource needs in order to meet reserve margin targets (See Chapter 6);
3. Identification of distinct portfolio options and strategies that include resource retirements and new resource additions over a long-term planning process;
4. Identification of a range of external uncertainties that could impact DESC's future portfolio costs; and
5. Evaluation of all portfolio options against the range of external uncertainties in a modeling framework that includes portfolio dispatch and financial revenue requirement accounting.

CRA's review of the IRP analysis in this chapter focuses on Steps 3-5 and broadly falls into the categories of **portfolio development**, **scenario analysis**, and **modeling framework.** The remainder of this section provides an overview of each category, with subsequent sections reviewing detailed assumptions and providing CRA's opinion on their reasonableness.

7.3.1. Portfolio Development

The 2020 IRP evaluates different resource options as alternatives to meet future customer demand reliably. To perform this analysis, DESC first developed a forecast of future system needs (i.e., the load forecast discussed in Chapter 5) and then determined the threshold of resource adequacy needed to provide reliable services to customers (i.e., the reserve margin analysis discussed in Chapter 6).

DESC then developed eight distinct resource plans for evaluation with varying retirement dates for existing units and different replacement resource options to meet future needs. These plans are summarized in Table 15.

In the development of its eight resource plans, DESC considered early retirement of current generating assets and a range of new resource options, including natural gas combined cycle ("CC"), two types of internal combustion turbines ("ICT"), solar (owned and via power purchase agreement), and energy storage. DESC also evaluated five alternative resource plans proposed by the SBA.

Table 16: Overview of Resource Plans Evaluated in 2020 DESC IRP

Portfolio Name	Early Retirements Considered	Resource Replacement Theme
RP1	N/A	Gas Combined Cycle & Combustion Turbine
RP2	N/A	Gas Combustion Turbine
RP3	Wateree 1 &2 retire in 2028	Gas Combined Cycle & Combustion Turbine
RP4	McMeekin 1 & 2 retire in 2028 Urquhart 3 retires in 2028	Gas Combustion Turbine
RP5	N/A	Owned Solar + Storage with Combustion Turbines
RP6	N/A	Owned Solar with Combustion Turbines
RP7	N/A	Contracted Solar + Storage with Combustion Turbines
RP8	Wateree 1 & 2 retire in 2028 Williams 1 retires in 2028	Low Carbon Plan, combines Combined Cycles, Combustion Turbines, Solar + Storage
SBA RP1	N/A	Contracted Solar with Combustion Turbine with Base DSM
SBA RP2	Williams 1 retires in 2028	Contracted Solar and Contracted Storage with SBA DSM
SBA RP3	Wateree 1 & 2 retire in 2026 Williams 1 retires in 2026	Contracted Solar + Storage with capacity purchases with SBA DSM
SBA RP4	McMeekin 1 & 2 retire in 2029 Urquhart 3 retires in 2029	Contracted Solar + Storage, Contracted Storage with SBA DSM
SBA RP5	N/A	Contracted Solar and Contracted Storage with Base DSM

7.3.2. Scenario Analysis

The resource plans were then evaluated across a range of scenarios to test the impacts of changes in load, fuel prices, carbon prices, and costs for new solar resources. These are summarized in Table 16.

All of the resource plans were evaluated using three gas price forecasts plus $0 and $25 per ton CO_2 costs. The DESC scenarios were further tested under each carbon and gas price combination using the Low and High DSM forecasts discussed in Chapter 5. The SBA portfolios were tested under each fuel and carbon view, but used just one DSM assumption per case as described in Table 15.

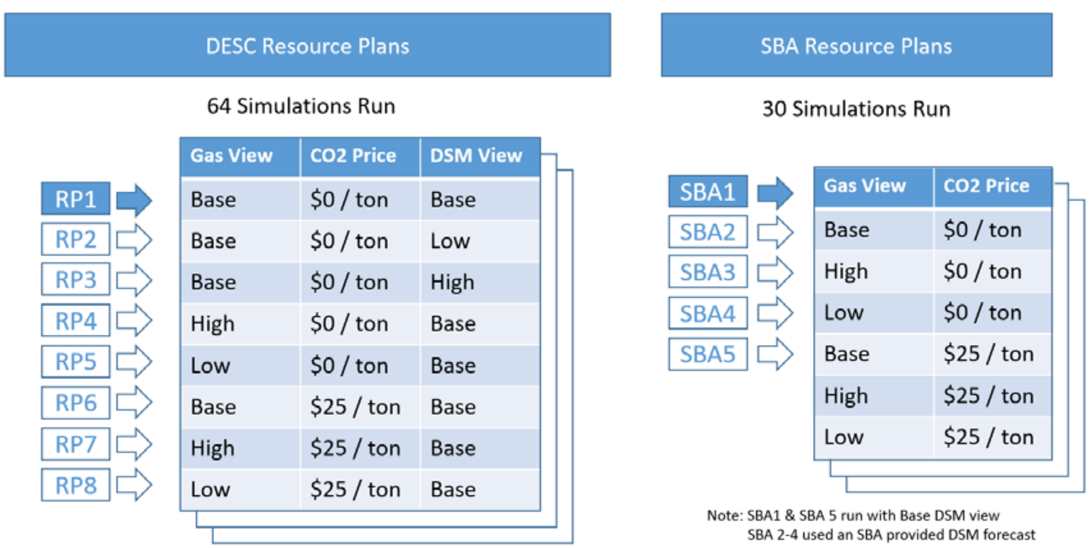
Table 17: Overview of Scenario Input Ranges

Scenario Variable	Description of Range	Additional Comments
Natural Gas Prices	DESC 2034 Henry Hub estimates range from $3-$6/MMBtu	Forecasts developed through analysis of NYMEX and EIA data
Carbon Price	DESC tested all portfolios with a $0 and $25 / ton CO_2 price	Under $25 CO_2 case, prices start in year 2025 and rise at 2%
Load Growth	DESC modeled winter peak growth forecasts ranging from 0.4% to 0.9% per year	Changes in Long-term load growth are driven by varying DSM assumptions
Solar Costs	DESC modeled 2026 solar PPAs with costs ranging from $36 to $49 / MWh	Solar PPAs in the SBA scenarios costed at NREL Low values

In all, DESC ran 94 dispatch simulations in PROSYM that combined each of the DESC and SBA portfolios with different combinations of fuel prices, CO_2 prices, and load outlooks. Figure 21 illustrates how these simulations were structured. Each of the eight resources plans developed by DESC were tested against eight scenarios that varied views on gas prices, CO_2 prices, and DSM penetration for a total of 64 simulations. Each of the five SBA resource plans were tested against six scenarios stressing CO_2 prices and gas prices.

PROSYM was used to run each of these simulations and produced an output detailing the system costs and emissions for each portfolio under the future market conditions. DESC compared the outputs of these simulations and selected the DESC resource plan that performed the best under the set of $0 carbon price forecasts.[67]

Figure 21: Combinations of Resource Plans & Scenarios Modeled in the 2020 IRP



67 DESC did not consider the SBA cases as candidates for the preferred resource plan as part of the 2020 IRP because these plans included assumptions that were not supported by the 2019 Potential Study and DESC resource cost estimates.

7.3.3. Modeling Framework

DESC relied principally on two tools for the IRP analysis: (i) PROSYM, a dispatch and portfolio accounting model, and (ii) an Excel-based revenue requirement model to integrate full financial accounting. The remainder of this section describes these tools in more detail.

Overview of PROSYM

PROSYM is an electricity system production cost model broadly used for energy market modeling, dispatch analysis, and price forecasting. PROSYM is widely deployed across the electricity industry.[68] PROSYM allows for extensive user customization, making it an effective tool for analyzing the effects of key variables, including fuel prices, load uncertainty, resource availability and emissions on a utility's variable production costs.

PROSYM on its own does not contain the capability to perform long-term capacity expansion ("LTCE"), a function which optimizes generation costs over time by making new build and retirement decisions. An LTCE process will maintain a utility's required reserve margin using the least-cost portfolio, given a list of available retirements and new resources. LTCE decisions weigh ongoing variable and fixed costs of existing units with new unit operating characteristics and expected capital and fixed spending required to bring these new units into service.

Implications of using PROSYM for Portfolio Modeling

PROSYM is a suitable tool for analyzing the expected dispatch and resulting costs of the DESC portfolios under various market conditions. However, not utilizing a model with LTCE functionality limits the portfolio options to a pre-defined list with pre-determined addition and retirement years. LTCE optimization would likely provide added insight into the DESC portfolio as it relates to early retirement options, the impact of new resource timing, and varying combinations of new resources. An LTCE simultaneously tests all possible combinations of these factors under differing load, fuel, and policy environments which could potentially identify cost savings or portfolio risks which would otherwise not be apparent.

Overview of Revenue Requirement Model

In order to fully analyze the cost of resource plans, DESC combined the outputs of PROSYM, which include variable O&M, fuel, emissions, market purchases and sales, and fixed O&M costs of existing and new generation, with the capital costs associated with new resource builds. This is done in a spreadsheet model that receives PROSYM outputs and incorporates additional financial accounting, as described below.

To calculate the annual cost of adding new capital, DESC uses a traditional utility revenue requirement approach, which calculates annual depreciation, return on capital, income tax and other taxes, and insurance associated with each new capital addition. When utilities make capital expenditures, unlike with operating expenditures, they charge customers for both the

[68] ABB describes PROSYM as: "The industry's leading chronological simulation engine used by over 130 customers worldwide for over three decades. The highly flexible user interface on ABB's EPM platform enables users to determine the granularity of the market to be analyzed – from ten minute to four hourly time periods, or from single control areas to entire continents. [PROSYM] is built on the ABB Energy Portfolio Management (EPM) Framework, providing a wide array of data and run management features designed to ease the workflow associated with managing vast amounts of regional electric market data. The interface allows users to manage data and conduct price evaluations at the zonal level, and manage the results of these investigations seamlessly through graphs and custom reporting."

cost of the expenditure, in the form of depreciation, as well as a return on capital associated with the investment. The annual return on capital is calculated using a rate-base approach, where DESC earns a return equal to its weighted average cost of capital on the undepreciated value of the investment every year. CRA has reviewed DESC's approach to determining capital recovery schedules and believes they are reasonable.

DESC has calculated a "generic" capital recovery for each type of new generation that is built, including new ICTs, natural gas combined cycle, coal (environmental spend on existing units), solar, and batteries. The capital recovery schedules for each type of generation change slightly by technology type, due to different tax depreciation schedules, estimates of useful life, and estimates of property taxes/insurance. To determine the cost of adding a new plant in each resource plan, DESC employs these "generic" recovery schedules and applies them to the capital expenditures associated with each new addition. DESC then sums the total annual capital recovery costs to calculate an annual New Generation Capacity Cost associated with each portfolio. In the revenue requirement model, DESC combines all PROYSM output, as discussed above, with the annual New Generation Capacity Costs as well as the annual DSM costs associated with each portfolio/scenario and calculates an annual revenue requirement for each portfolio under each scenario.

7.4. Reasonableness of Portfolio Development and Assumptions

7.4.1. Reasonableness of Portfolio Development Approach

DESC's approach for portfolio development was generally reasonable, as the IRP evaluated a range of future resource options around the existing fleet as well as future new resource additions. The range of new candidate technologies considered was reasonable and consistent with what CRA has observed in other IRPs.

The PROSYM tool does not include a capacity expansion optimization function, which has limited the ability of DESC to provide specific justification for certain resource choices and the timing of retirement and new addition decisions. Any IRP exercise requires some level of expert judgment and user-defined portfolio development, as simple least-cost planning is never sufficient in the face of significant market uncertainties and potentially competing planning objectives. However, a least cost optimization tool would provide DESC with an ability to enhance its portfolio development process, and DESC may consider the integration of such a capability for future IRPs.[69]

7.4.2. Reasonableness of Cost Assumptions for New Resources

DESC's IRP included a set of six permanent supply-side resource options: a gas combined-cycle, a frame gas internal combustion turbine, an aero gas internal combustion turbine, solar, contracted solar, and lithium-ion battery storage. These resource options are consistent with those being evaluated by other utilities across the country and are consistent with the supply-side options that CRA recommends to include in an IRP analysis.

There are several other generation technologies that DESC, for numerous reasons, did not include as resource options in its analysis: onshore wind, offshore wind, nuclear, and carbon capture and sequestration ("CCS")-equipped coal and gas. Local onshore wind resources in SERC are limited in both availability and performance and are likely to be less economic than solar. The cost and performance parameters for offshore wind are very site-specific, and these

[69] Interview with DESC Experts Eric Bell, Joseph M. Lynch, James Neely, and Joseph Stricklin.

projects may have major implementation challenges and can have uncertain costs, making it difficult to model without project-specific parameters. Likewise, new nuclear resources currently have major implementation challenges and cost uncertainty. Additionally, most new nuclear technologies are only available in very large block sizes and are not as modular as new gas or solar technologies. Finally, carbon-capture technologies are still in the nascent stages of proven viability and are not likely economic currently.

Capital Cost Assumptions

The capital costs used by DESC are summarized in Table 18 and are largely in line with the supply-side capital costs that are most commonly used in the industry. Future cost decline curves for solar and lithium-ion batteries are more aggressive than future decline curves for thermal resources, meaning that over time the capital costs for new thermal resources tend to get more expensive, while capital costs for solar and batteries decline.

DESC evaluated solar and solar plus storage resources, which are both eligible to receive an ITC. However, for owned resources built in 2026, DESC assumed no capital cost discount associated with the ITC. For PPA resources, on the other hand, DESC incorporated the ITC into the PPA cost through its levelized cost calculation. The levelized cost calculation is described in more detail below.

CRA believes that DESC may have taken a conservative approach to calculating the value of the solar ITC for owned resources. However, since these resources would be owned by DESC, monetization of the ITC could be challenging. Additionally, since no owned-solar is added in any plan prior to 2026, the value of the credit would only be ten percent, so the forgone cost savings are much lower than for projects that receive the full ITC. Therefore, CRA does not think that these assumptions bias DESC outcomes, given the relatively low capital costs assumed for solar, shown in Figure 32.

CRA believes that DESC may also have been conservative in its ITC assumptions for PPAs; DESC has assumed that full ITC qualification ends in 2019, and the ITC steps down to 10% from 2020-2022. While this is not an unreasonable interpretation of the current IRS rules, it does not account for developers that have already safe harbored solar technology and can place the project in service years later.[70] Since most solar PPAs are added when ITC values are expected to be low and solar capital costs are low, this assumption does not materially affect the outcome of any plan.

[70] Despite the ITC stepdown starting after 2019, developers can safe harbor ITC for up to four years if they incur at least five percent of the project costs in that year and receive the full ITC for that year. So for example, a project safe harbored in 2019 could enter into service in 2023 and still receive a 30% ITC.

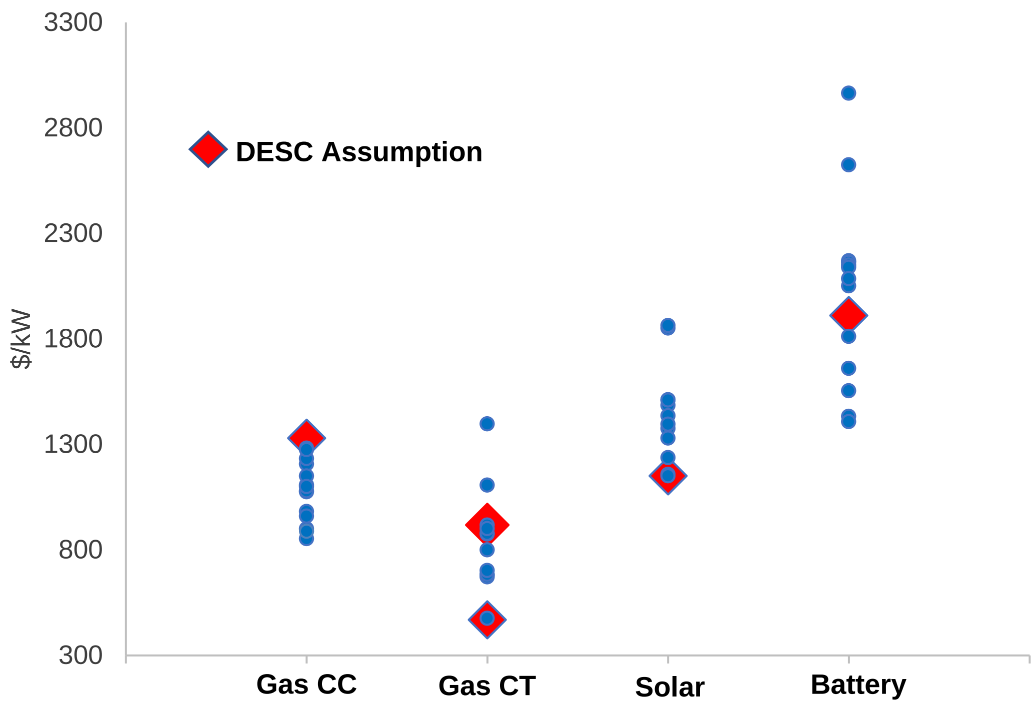
Table 18: Capital Cost ($/kW – Nominal) by Technology Type

	Battery	CC (1-on-1)	ICT Frame J (2x)	ICT Aero (2x)	Solar
2020	1911	1330	469	918	1151
2021	1864	1380	487	952	1134
2022	1818	1432	505	988	1117
2023	1773	1485	524	1025	1100
2024	1730	1541	543	1064	1084
2025	1687	1599	564	1104	1067
2026	1645	1659	585	1145	1051
2027	1605	1721	607	1188	1036
2028	1565	1785	630	1232	1020
2029	1527	1852	653	1279	1005
2030	1489	1922	678	1327	990
2031	1453	1994	703	1376	975
2032	1417	2069	730	1428	960
2033	1382	2146	757	1481	946
2034	1348	2227	785	1537	932
2035	1315	2310	815	1595	918
2036	1282	2397	845	1654	904
2037	1251	2487	877	1716	891
2038	1220	2580	910	1781	877
2039	1190	2677	944	1848	864
2040	1161	2777	979	1917	851

CRA has observed solar capital cost estimates as low as $1,100/kW for new solar and as high as $1,800/kW. CRA has observed battery costs ranging from $1,400/kW to over $3,000/kW. For gas combined cycle units, CRA has observed industry costs between $900/kW and $1300/kW. For gas turbine technologies, CRA has observed industry costs as low as $476/kW for simple cycle turbines and as high as $1,300/kW for more advanced aeroderivative technologies.

DESC's solar costs are on the lower end of the estimates that CRA has reviewed, but solar prices have fallen considerably in the last decade and this trend is expected to continue. CRA believes these solar costs are reasonable. Capital costs for storage units fall firmly in the middle of the range of estimates reviewed by CRA and are reasonable. DESC's costs for new thermal gas resources are also supported by the range of estimates CRA has reviewed. Costs for thermal resources can vary widely based on siting, location and technology used, so CRA finds that DESC's costs are reasonable. The figure below shows DESC's cost assumptions plotted against the various public sources and IRPs that CRA has compiled.

Figure 22: Capital Costs – DESC vs. Public Sources and Utility IRPs[71]



Variable Cost Assumptions

In the DESC IRP, gas combustion turbine and combined cycle units were assigned a $0.34/MWh variable operations and maintenance cost ("VOM"). The DESC assumption of $0.34/MWh includes chemical and water costs associated with environmental equipment. Table 19 summarizes the VOM cost estimates for gas generators found in recent industry studies. The DESC assumption of $0.34/MWh is supported by the estimates reviewed by CRA and is reasonable in CRA's view, even if it is on the low side of the range.

The lower VOM cost assumption does not, in CRA's view, bias the analysis in favor of gas. Non-fuel VOM is a small component of operating costs for gas-fired units and CRA does not expect this assumption to significantly impact when PROSYM would dispatch an efficient new combined cycle unit nearly as much as the fuel or carbon sensitivities considered in the 2020 IRP. For a combustion turbine, which is less efficient and often only operates in periods of high load, CRA does not expect the VOM assumption to impact dispatch in PROSYM. Further, because combustion turbines run at low capacity factors, the impact on total system costs used to evaluate the DESC portfolios is minor.

71 Public sources and utility IRPs include: Lazard, EIA, NREL, EPRI, IRENA (Public); Puget Sound Energy, Avista, Idacorp, Wabash Valley, Dominion, Ameren, NIPSCO, Northwestern, Consumers, AEP, PGE (IRPs)

Table 19: VOM Cost Estimates

Source	Resource Type	VOM ($/MWh)
Lazard[72]	Gas Combustion Turbine	4.75-6.25
	Gas Combined Cycle	3.00 - 3.75
2020 AEO[73]	Gas Combustion Turbine	4.48 - 4.68
	Gas Combined Cycle	1.86 – 2.54
California ISO[74]	Gas Combustion Turbine	0.82 - 1.88
	Gas Combined Cycle	0.26 - 2.64

Fixed Cost Assumptions

DESC has assumed that new technologies have a generic fixed operations and maintenance cost, typically expressed on a dollar-per-kilowatt-year basis. The fixed O&M assumptions for new resources are shown in Table 20.

Table 20: DESC Fixed O&M Assumptions by Technology Type

	CC (1-on-1)	ICT Frame J (2x)	ICT Aero (2x)
Fixed O&M ($2020/kW-yr)	8.81	5.66	12.61
Growth Rate	2% (through 2028); 3.41% (after 2028)	2% (through 2028); 3.41% (after 2028)	2% (through 2028); 3.41% (after 2028)

Table 21 summarizes the fixed O&M estimates for new gas resources from several industry sources. DESC's fixed O&M assumptions are reasonable and within the range of fixed cost assumptions reviewed for their respective technology types.

[72] Lazard's Levelized Cost of Energy Analysis Version 13.0. <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>

[73] 2020 Annual Energy Outlook. Table 3. Cost and Performance characteristics of new central station electricity generating technologies. <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>

[74] California ISO – Variable Operations and Maintenance Cost – December 26, 2018

Table 21: Fixed O&M Cost Estimates

Source	Resource Type	Fixed O&M ($/kW-yr)
Lazard 2019[75]	Gas Combustion Turbine	5.50 – 20.75
	Gas Combined Cycle	11.00 – 13.50
Lazard 2018[76]	Gas Combustion Turbine	5.00 – 20.00
	Gas Combined Cycle	5.50 – 6.00
2020 AEO[77]	Gas Combustion Turbine	6.97 – 16.23
	Gas Combined Cycle	12.15 – 14.04
Ameren 2017 IRP[78]	Gas Combustion Turbine	7.90
	Gas Combined Cycle	8.10

DESC did not assume any fixed O&M costs for new owned solar or batteries. DESC has modeled property taxes and insurance as part of the capital cost estimates, which are sometimes included in estimates of fixed O&M. While these generation technologies do not typically have any *variable* costs to operate, they do have fixed labor and materials costs in excess of property tax and insurance. CRA believes that assuming zero fixed costs for owned solar and batteries may understate the actual cost of these resources. However, CRA does not believe that this materially impacts the result of the DESC IRP.

7.4.3. Reasonableness of Performance Assumptions for New Resources

Each supply-side option comes with a set of operational parameters used for dispatch modeling. CRA has compared the assumptions that DESC used in the IRP with other public sources used across the industry. Table 22, Table 23, and Table 24 summarize the assumptions for thermal, solar, and battery storage resources used in the DESC IRP. CRA reviewed these assumptions in the context of assumptions used by the Energy Information Agency (“EIA”) in its latest Annual Energy Outlook (“AEO”) forecast and Lazard’s most recent technology cost benchmarking study.

75 Lazard’s Levelized Cost of Energy Analysis Version 13.0. <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>

76 Lazard’s Levelized Cost of Energy Analysis Version 12.0. <https://www.lazard.com/media/450773/lazards-levelized-cost-of-energy-version-120-vfinal.pdf>

77 2020 Annual Energy Outlook. Table 3. Cost and Performance characteristics of new central station electricity generating technologies. <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>

78 Ameren 2017 Integrated Resource Plan. Appendix 6A. <https://www.ameren.com/-/media/missouri-site/files/environment/2017-irp/chapter-6-appendix-a.pdf>

Table 22: Gas Performance Assumptions in DESC IRP

	CC (1-on-1)	ICT Frame J (2x)	ICT Aero (2x)
Block Size (MW)	553	523	131
VOM ($/MWh)	0.34	0.34	0.34
Hot Start Fuel (MMBtu)	1,292	74	40
Cold Start Fuel (MMBtu)	3,877	74	40
Non-Fuel Startup Costs ($/start)	N/A	30,551	1,500
Estimated Starts per Maint. Cycle	N/A	1,100	1,100
Equivalent Forced Outage Rate	5%	5%	1%
Summer Heat Rate at Min (MMBtu/MWh)	7.071	15.217	12.05
Summer Heat Rate at Max (MMBtu/MWh)	6.368	9.668	9.324
Winter Heat Rate at Min (MMBtu/MWh)	7.019	14.386	10.494
Winter Heat Rate at Max (MMBtu/MWh)	6.3	9.364	9.131
NO_x Emissions Rate (lb/MMBtu)	0.0072	0.0333	0.007
SO_2 Emissions Rate (lb/MMBtu)	0.00114	0.000608	0.00114
CO_2 Emissions Rate (lb/MMBtu)	116.98	118.28	116.98
Maintenance Rate	12%	9%	1%
Min Up Time (hours)	8	2	1
Min Down Time (hours)	6	6	1

Table 23: Solar Performance Assumptions in DESC IRP

	Solar	Solar PPA
Block Size (MW)	100 or 400	400
Annual Degradation	0.5%	0.5%
Capacity Factor	23.8%	23.8%

Table 24: Storage Performance Assumptions in DESC IRP

	Battery Storage
Block Size (MW)	100
Maximum Storage Contents (MWh)	400
Duration (hours)	4
Annual Degradation	0%
Roundtrip Efficiency	82%

Block Size

DESC assumed a 553 MW block size for a new gas combined cycle unit in the 2020 IRP. Block size assumptions in the latest EIA AEO forecast was 418MW, and Lazard's latest view assumed a 550 MW combined cycle block size.[79,80] DESC's assumptions are reasonable in CRA's view.

DESC considered two types of ICT units in the 2020 IRP: a 2x1 frame ICT with a block size of 523MW and an aeroderivate ICT with a block size of 131 MW. EIA used a block size of 237 MW for an industrial frame combustion turbine in its latest study. Because DESC is using a 2x1 configuration for the frame ICT, this is consistent with the EIA assumptions. For an aeroderivative ICT, EIA uses a block size of 105 MW, which is slightly smaller than the 131 MW block size used in the DESC IRP.[81] However, DESC examined a smaller 93 MW aeroderivative block size in the intervenor resource plans, and this block size was a reasonable assumption.

DESC adds new solar resource in 100 MW and 400 MW blocks in certain 2020 resource plans in the 2020 IRP. The 400 MW block size for solar is identical in operations to the 100 MW option and can be considered equivalent to four 100 MW solar blocks. DESC's assumption is consistent with the block sizes assumed by EIA and Lazard of 115MW and 100MW, respectively, in their latest reports.[82, 83] While the size of a solar resource is site-dependent, a block size of 100 MW is reasonable for high-level planning purposes.

DESC adds new storage resources in 100 MW blocks in certain 2020 resource plans, sometimes paired with solar in a 4:1 ratio (i.e., 400 MW of solar paired with 100 MW of storage). DESC's assumption compares with a block size of 50 MW in the latest EIA study, which was also paired with solar in a 4:1 ratio (i.e., 200 MW of solar paired with 50 MW of storage).[84] CRA views the block sizes assumed in the 2020 IRP as reasonable, but notes that smaller blocks of solar and storage at the 4:1 ratio are common and could be considered in future study.

Efficiency and Output

CRA compared DESC heat rate inputs to those found in the Lazard levelized cost of electricity ("LCOE") study. For a new combined cycle, Lazard estimates a heat rate between 6,133 and 6,900 Btu per kWh.[85] DESC's assumption of 6,368 Btu/kWh falls within this range and, in CRA's view, is reasonable. Lazard estimates a heat rate for a combustion turbine to be between 8,900 and 9,900 Btu/kWh.[86] Both of DESC's ICT options fall within this range and, in CRA's view, the assumptions are reasonable.

79 2020 Annual Energy Outlook. Table 3. Cost and Performance characteristics of new central station electricity generating technologies. <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>

80 https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

81 2020 Annual Energy Outlook. Table 3. Cost and Performance characteristics of new central station electricity generating technologies. <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>

82 Ibid.

83 https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

84 2020 Annual Energy Outlook. Table 3. Cost and Performance characteristics of new central station electricity generating technologies. <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>

85 https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

86 Ibid.

Lazard estimates the capacity factor for utility scale solar to be between 21% and 32%.[87] DESC assumed a solar capacity factor of 23.8%, a composite of the actual capacity factors at several existing solar resources in DESC's service territory. This is within the Lazard range and a reasonable assumption in CRA's view.

DESC refers to new "flexible solar" resources in the construction of its resource plans.[88] All existing solar resources and planned solar PPA additions through 2022 are modeled in PROSYM as non-curtailable resources, meaning that other units on the system must ramp down to allow for energy from these units to be delivered to the system in periods of low load and high solar output.[89] By contrast, new DESC-owned solar and solar PPAs added to the DESC resource portfolio in 2026 and beyond are considered curtailable. SBA included some non-curtailable PURPA solar as part of its portfolio assumptions.[90]

Flexible solar means that that these units are able to operate below maximum capacity as needed to accommodate changes in system load, providing cost savings that benefit the wider system. DESC does not assume any additional costs are incurred by solar units to allow for this capability. This may understate the actual cost of these units given this capability is added without cost and that solar PPA costs are calculated based on the annual average capacity factor of 23.8%, but will actually dispatch at a lower capacity factor due to curtailment.

Duration, size, and roundtrip efficiency are close to the standard assumptions that CRA uses for modeling lithium-ion batteries and those estimated by the 2019 EIA study "Energy Storage Technology Cost Characterization Report".[91] DESC assumes that all the capital costs associated with the batteries are recovered by year 10, but the battery remains on the system providing energy and capacity, with the energy value degrading at 2 percent annually. CRA believes this assumption could understate the true costs of the battery, as some fixed O&M or ongoing capital spending would be needed after ten years to replace the battery modules and preserve the energy and capacity value of the unit.

Other Operational Parameters

According to EIA data, the carbon emission rate for natural gas is 117.0 lb/MMBtu, which is close to the DESC range of 116.98-118.28 lb/MMBtu, depending on the type of generator. The emission rates for SO2 and NOx are within a reasonable range and are not a major driver of gas unit operations or costs.

While forced outage rates depend on the specific turbine type and operations, the average forced outage rate for a combined cycle in PJM, the largest ISO market in the US, was 4.8% from January to March 2020, and the average forced outage rate for a combustion turbine was 4.3%.[92] Given that this average includes existing units, the DESC assumptions of 5% and 1% appear reasonable.

87 Ibid

88 2020 DESC IRP pg. 40

89 Ramp down of units can increase cost to the system as many thermal units are less efficient at minimum load, further when units must shut down completely, they will incur future start costs.

90 Interviews with James Neely and Eric Bell.

91 https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

92 http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q1-som-pjm-sec5.pdf

CRA compared the remaining inputs, including startup costs, maintenance rates, and minimum up and down times, to assumptions used by CRA in its own resource modeling. These assumptions are provided by Energy Exemplar and further informed through a scan of other public sources including other utility IRPs and engineering studies. Based on evaluation of these inputs, the assumptions used by DESC for the 2020 IRP are reasonable.[93]

Reasonableness of DESC approach to estimating seasonal RM contribution of new resources

New resource options are assigned a peak credit percentage that relates to how much the resource contributes to base reserves in both summer and winter. CRA reviewed the methodology used by DESC to determine how each potential new resource type contributed to seasonal base reserve margin requirements. Table 25 summarizes the peak credit given to each installed MW of capacity by resource type in the DESC IRP.

Table 25: Peak Credit for New Resources in DESC IRP

	Summer Peak Credit	Winter Peak Credit
Battery Storage	100%	100%
Solar (first 1,000 MW)	46%	0%
Solar (after 1,000 MW)	8.8%	0%
CC (1-on-1)	100%	100%
ICT Frame J (2x)	100%	100%
ICT Aero (2x)	100%	100%

CRA finds the assumption of 100% summer and winter peak credit for gas and storage reasonable. Nameplate capacity for gas resources is commonly derated using the resource type's forced outage rate to determine the peak capacity credit. As summarized in Table 25, the forced outage rate for CC and ICT frame generators is assumed to be 5%, suggesting a peak credit of 95%. The forced outage rate for ICT Aero generators is assumed to be 1%, suggesting a peak credit of 99%. Given the block size for thermal resources, CRA has determined that these derates would not have impacted the buildout of any IRP portfolios. The assumption of 100% capacity credit for battery storage with 4-hour duration is reasonable and commonly applied in many markets, including MISO and SPP.[94],[95]

Solar contribution to reserve margin depends heavily on existing solar penetration in the region, load shape, and season. CRA reviewed DESC's methodology for determining peak credit for solar resources, as detailed in "The Capacity Benefit of Solar QFs 2018 Study" and accompanying testimony by Joseph M. Lynch in Docket No. 2019-2-E, "Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company." The study analyzed the average output of 7 solar resources in DESC's territory, finding that the solar did not contribute resource availability during the winter peak because the system peaks before sunrise. It also found that solar contributes an average of 46% on the five highest summer load days. Both of

[93] Sources and utility IRPs include: Lazard, EIA, NREL, EPRI, IRENA (Public); Puget Sound Energy, Avista, Idacorp, Wabash Valley, Dominion, Ameren, NIPSCO, Northwestern, Consumers, AEP, PGE (IRPs)

[94] Midcontinent Independent System Operator, an independent system operator that provides reliability services to a territory across 15 states across the Midwestern United States and Manitoba. https://www.misoenergy.org/about/

[95] Southwest Power Pool, an independent system operator with service territory across 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. https://spp.org/about-us/

these numbers are in line with CRA's expectations for solar peak credit by season. After 1,000 MW of solar, DESC assumes the solar summer peak credit is 8.8% given a shift in peak hours to later in the day at high levels of solar penetration in the system. This value is consistent with the results in "The Capacity Benefit of Solar QFs 2019 Study" and accompanying testimony of James Neely, which provided an update to the 2018 solar analysis.[96] Given that the winter reserve requirement is more binding than the summer reserve requirement, this assumption is reasonable for long-term planning purposes.

7.4.4. Reasonableness of PPAs Modeled and PPA Assumptions

DESC modeled PPAs for both solar and battery technologies. The assumptions for these technologies are shown in Table 26 and are sourced to NREL 2019, Mid Technology Cost in the 2020 DESC IRP.[97] For the SBA portfolios, DESC relied on the Low Technology Cost case from the 2019 NREL study for battery and solar assumptions. [98] CRA compared DESC's Solar PPA calculations, found in its "Levelized Cost of Energy 2019_021020" Excel file, against the capital costs from the NREL 2019 Annual Technology Baseline and validated that these assumptions were used.[99,100]

DESC estimated solar and battery PPA prices by calculating a levelized cost for development, operations, maintenance, financing (including return on capital), and taxes over the life of the asset. DESC assumed that all capital costs associated with the plant are recovered over a 20-year PPA period. DESC relied on financing assumptions from the EIA's Annual Energy Outlook (2019). CRA has found that these are reasonable assumptions for a merchant power producer. DESC accounts for the ITC by adjusting the capital recovery factor. The capital recovery factor is a levelized value, which determines the annual carrying costs of capital (depreciation, return on, and taxes). For the SBA scenarios, which call for a lower solar capital cost, DESC has used the same levelized cost approach, but employed a lower capital cost for solar, which results in a lower levelized cost of energy and thus a lower PPA price.

Table 26: DESC PPA Prices

PPA Price by Year	Base Case	SBA Scenario
2020 Solar	$50.49/MWh	$42.69/MWh
2025 Solar	$50.28/MWh	$38.03/MWh
2030 Solar	$44.39/MWh	$29.11/MWh
2035 Solar	$42.03/MWh	$25.21/MWh
2020 Battery	N/A	$180/kW-yr

[96] Response 2-15 from James Neely, Dominion Energy South Carolina Inc, Office of Regulatory Staff's Second and Continuing Request for Production of Books, Records, and Other Information. Docket No. 2019-226-E

[97] 2020 DESC IRP, pg. 39

[98] CRA found that DESC used the correct battery cost trajectory from NREL, but it has accelerated the forecast by one year (e.g. NREL's 2021 cost is DESC's 2020 cost assumption, etc.). As a result of this, DESC may understate the actual cost of battery PPAs, however, this difference is minor and does not materially impact the IRP analysis.

[99] NREL (National Renewable Energy Laboratory). 2019. 2019 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2019.

[100] CRA confirmed that the solar capital costs used by DESC for the base and low solar PPA cases match the NREL "Mid" and "Low" solar capital costs (DESC used the "Kansas City Region" as the closest proxy for its service territory).

2025 Battery	N/A	$105/kW-yr
2030 Battery	N/A	$74/kW-yr
2035 Battery	N/A	$68/kW-yr

For battery PPA costs, DESC determined levelized costs on a dollar-per-kilowatt-year basis rather than a dollar-per-MWh basis. This is appropriate for battery resources because they do not, on balance, add energy to the system, and are relied upon primarily as a firming resource to meet capacity requirements.

7.5. Reasonableness of Scenarios

Review of the Natural Gas Price Forecast Assumptions

Figure 23 illustrates the Henry Hub natural gas price forecast used for each of the fuel price scenarios in the 2020 DESC IRP. The Base and Low gas price forecasts use three years of NYMEX futures, escalated at different rates. The Base case forecast escalates at 4.40% per year until 2032 and then 3.0% per year thereafter. The Low case escalates at 2.20% per year until 2032 and then escalates at 1.5% per year thereafter. Finally, the High gas price forecast used the 2019 AEO Reference case as the commodity price input.

Figure 23: Natural Gas Price Forecasts from the 2020 IRP

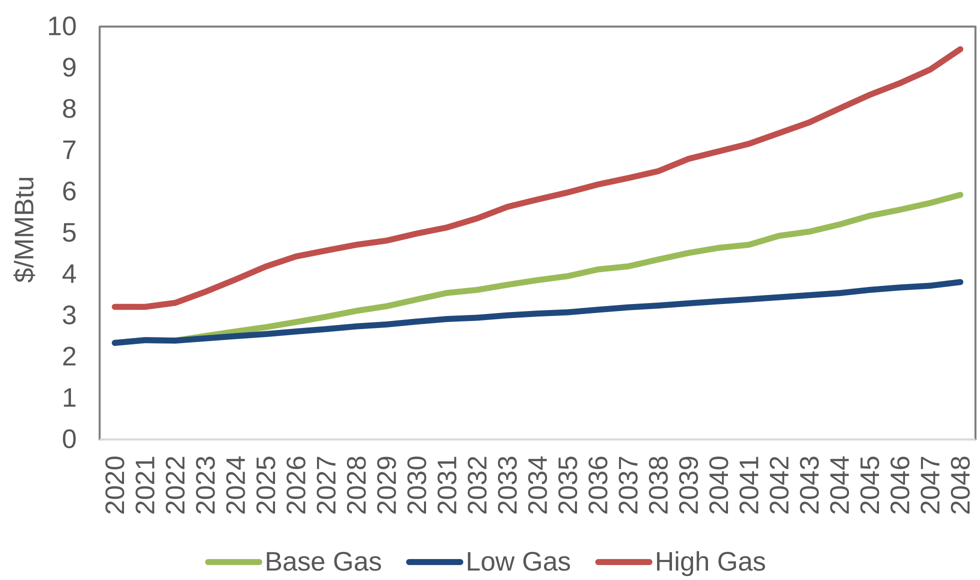
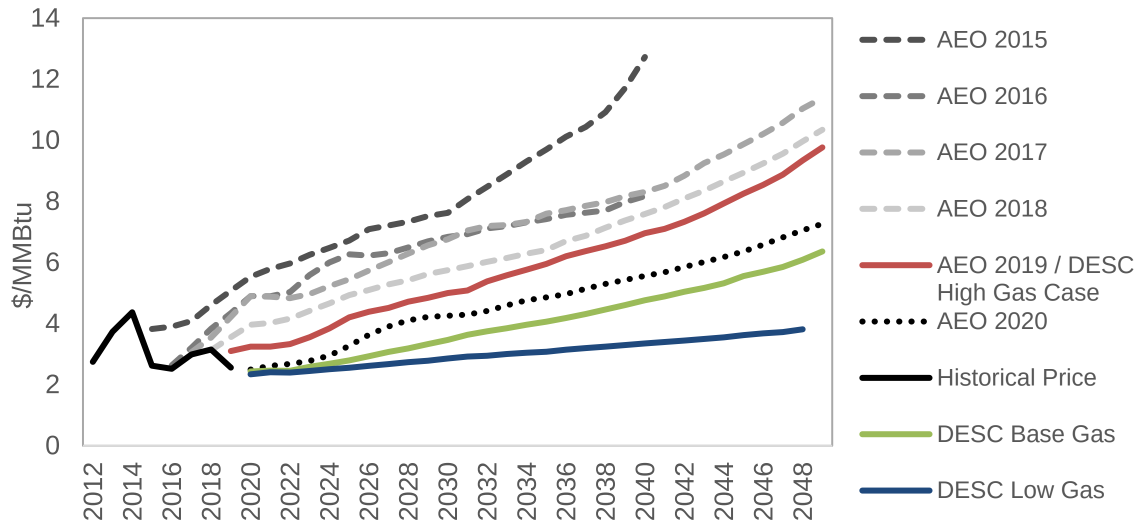


Figure 24 compares the gas price forecasts used by DESC to recent historical prices as well as the reference price forecast for Henry Hub in EIA's Annual Energy Outlook over the last six publications. Natural gas prices have trended downward in recent years due to record domestic production, driven by the proliferation of shale gas and oil drilling. Since the widespread adoption of fracking, long-term forecasts have been continually revised downwards, as illustrated in Figure 24.

The most recent 2020 AEO Reference case outlook is consistent with the DESC Base case over the first 5 years of the forecast. Given the consistent downward revision of the Reference case Henry Hub forecast and the current low price environment, the Base case forecast used in the 2020 IRP is reasonable.

Figure 24: Comparison of AEO Henry Hub Forecasts by Report Vintage to DESC Assumptions

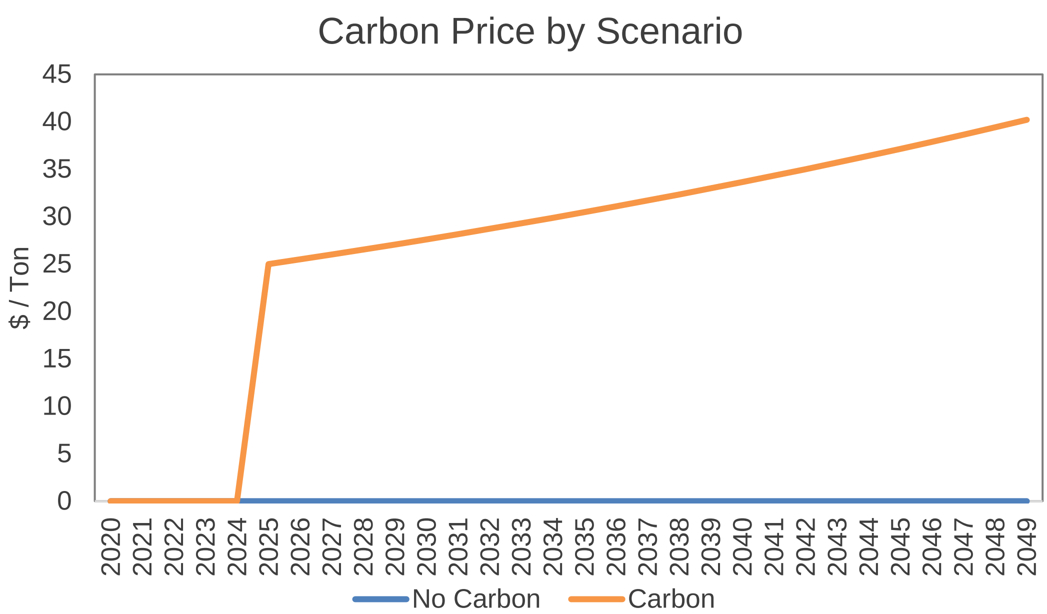


DESC's High gas scenario relied upon the AEO 2019 Reference case as the basis for the Henry Hub forecast. The AEO 2019 Reference case starts approximately $1 / MMBtu higher than DESC's Base case, growing to approximately $3 / MMBtu higher by 2040. This provides a materially different and higher view of the gas prices than DESC assumed for the Base case. Further, since 2019, EIA has revised the AEO Reference case downward, as illustrated in Figure 24. The AEO 2019 Reference case is consistently higher over the entire study period than the 2020 Reference case, supporting the decision to treat the AEO 2019 Reference case as the High case for the 2020 IRP. Since the portfolio cost results from the 2020 IRP already show some high renewable cases as lower cost when using the High gas scenario with no carbon price, an even higher gas trajectory would illustrate greater benefits for these portfolios but would not change the findings of the analysis.

Review of the Carbon Price Assumptions

DESC considered two different carbon price outlooks to evaluate future uncertainty around emissions requirements, illustrated in Figure 25. Under the $0 dollar carbon price scenario, DESC assumes no new regulations result in a price on greenhouse gas emissions from the electric sector. Under the $25 carbon price scenario, DESC assumes that all thermal units must pay an additional emissions cost when burning fossil fuels, causing these units to become more expensive. This cost starts at $25 / ton of CO_2 emitted in 2025 and grows at 2% per year over the forecast period, keeping pace with inflation.

Figure 25: CO_2 Price Scenarios from the 2020 DESC IRP



CRA believes it is reasonable to consider cases with and without long-term pressure on CO_2 prices as part of an IRP. A number of state and regional CO_2 pricing initiatives have been implemented that affect the electric sector in the U.S., including the Regional Greenhouse Gas Initiative in the Mid-Atlantic and Northeast and California's AB32. Currently, there is no federal system for pricing CO_2 emissions or state-specific CO_2 pricing program for the state of South Carolina.

Despite the lack of current standards, many stakeholder groups increasingly value sustainability and are putting pressure on legislators and regulators to take actions that lower greenhouse gas emissions. The US Environmental Protection Agency ("EPA") proposed to, but ultimately did not, put state-level limits on CO_2 emissions from the power sector and allow for CO_2 trading under the Clean Power Plan.[101] Federal legislators from both parties have proposed carbon pricing proposals in the past.[102] DESC was reasonable to evaluate scenarios in which efforts to implement a price on greenhouse gas emissions are ultimately successful.

Many utilities throughout the country and the region have also considered the impact of emissions pricing as part of their long-term planning, as seen in Table 27.[103] Duke, Georgia Power, and TVA all model scenarios in which CO_2 prices are implemented in the mid-2020s, in line with the timing of the CO_2 price scenario used by DESC in the 2020 IRP. Further, the price level of the DESC assumption, \$25 / ton and rising at 2% per year, is consistent with the range of trajectories considered in the IRPs CRA has reviewed.

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[101] https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan-0

[102] https://archive.epa.gov/epa/climatechange/climate-stewardship-and-innovation-act-2007-july-2007.html; https://www.congress.gov/bill/110th-congress/senate-bill/3036

[103] CRA also reviewed the main IRP documents of Santee Cooper, Alabama Power, FPL, Gulf Power, and TECO and did not find reference to CO_2 price scenarios but did not check all appendices and supporting documents.

Table 27: Emissions Scenarios Evaluated in Recent IRPs

Utility Name	CO_2 Scenario Description
Duke Energy Carolinas[104]	• Base CO_2 Price – CO_2 tax starting at $5/ton in 2025 and escalating at $3/ton annually • High CO_2 Price – CO_2 tax starting at $5/ton in 2025 and escalating at $7/ton annually
Duke Energy Progress[105]	• Base CO_2 Price – CO_2 tax starting at $5/ton in 2025 and escalating at $3/ton annually • High CO_2 Price – CO_2 tax starting at $5/ton in 2025 and escalating at $7/ton annually
TVA[106]	• Growth Case - $5/ton in 2025 escalating at inflation • Decarb Case - $25/ton in 2025 escalating at inflation rate, increases by additional $10/ton in 2035
Georgia Power[107]	• $10/ton CO_2 starting in 2026, rises 5% annually • $20/ton CO_2 starting in 2026, rises 5% annually

Review of the Load Scenario Assumptions

Chapter 5 discusses the DESC load forecast, including the range of scenarios considered in detail. DESC modeled a range of peak and energy forecasts driven by High and Low penetration levels of DSM developed from the 2019 DSM Potential Study, in addition to a DSM view provided by SBA. CRA finds the load forecasting models and methods used by DESC to be reasonable. DESC's 2020 IRP provides a reasonable Base case view. Moreover, DESC evaluated a range of load forecasts that capture a reasonable range of uncertainty around the Base case view. CRA notes that many regional utilities did not include load scenarios as part of their resource planning documents. Compared with utilities that included load sensitivities as part of their IRP analysis, the overall range of the scenarios considered by DESC could be expanded in future IRPs to include lower probability events.

7.6. Review of DSM Application in Portfolio Construction

The DSM forecasts relied upon in the 2020 IRP are based on the 2019 DSM Potential Study developed by ICF and on assumptions provided directly to DESC by the SBA.[108] DESC included two qualitatively different types of demand side measures in the 2020 IRP: energy efficiency ("EE") and load management, sometimes called DR. EE typically includes actions

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[104] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de

[105] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7f4b3176-95d8-425d-a36b-390e1e57a175

[106] https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan

[107] GA PSC Document #175473

[108] The ICF report "Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan" (the "2019 Potential Study") was approved by Commission in December 2019 pursuant to Commission Order No. 2019-880.

that reduce the energy needed to maintain the same level of production or comfort. DR typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

The 2019 Potential Study prepared by ICF was an update to a similar 2009 study that served as the basis for the “Current Programs” already implemented by DESC to promote DSM in its service territory. The 2019 Potential Study evaluated the potential 10-year energy and peak savings from a broad range of EE and DR measures and subjected them to a series of cost-benefit tests. Based on the results of this analysis, ICF developed a recommended “Expanded Program” of DSM options that are cost effective and also estimated the expected incremental savings of these measures in terms of total sales and peak energy.

Review of Energy Efficiency

Table 28 contains the energy efficiency options included in the 2020 DESC IRP. These correspond to the Expanded Program in the 2019 Potential Study prepared by ICF.

Residential programs focus on providing incentives for customers to choose more efficient lighting, heating ventilation and cooling (“HVAC”) equipment, and water heating equipment, in addition to providing customers with more information about their energy consumption. Commercial programs provide incentives for lighting and equipment improvements, including a program targeting small businesses. Industrial programs include incentives for efficient motors and equipment, in addition to education and incentives targeted at select potential industrial and agricultural customers with high savings potential.

Table 28: Energy Efficiency Measures included in the DESC DSM Program

Residential	Commercial	Industrial
Appliance Recycling Heating & Cooling Home Energy Check-up Home Energy Reports Neighborhood EE ENERGY STAR® Lighting Multifamily EE Water Heating	EnergyWise Incentives Small Business Energy Solutions Municipal LED Lighting	EnergyWise Incentives Strategic Energy Management

ICF tested 454 measures and 1,442 permutations of those measures for cost-effectiveness and applied a Total Cost Recovery (“TCR”) test to all measures to evaluate cost effectiveness.[109] The TCR test evaluates the expected benefits, which include avoided energy costs, avoided capacity costs, and other non-electricity savings over the lifetime of the measure against the baseline technology. The TCR compares these benefits to the expected costs of the measure, which include the difference in equipment and labor costs relative to the baseline technology.

[109] A measure with a TRC result of 1.0 indicates that the measure is cost-effective on a stand-alone basis, a higher TRC is better indicating that a measure saves more than it costs, while a TRC lower than 1 indicates that savings do not cover the stand-alone cost of the measure

Measures that scored 1.0 or higher on this test – meaning their lifetime benefits were greater than their costs - were subjected to the next phase of the analysis to narrow down options to the most cost effective in each use case and customer segment. About 70% of the measures originally evaluated with the initial TCR test were included in energy efficiency programs.[110]

To determine the amount of potential savings, ICF first evaluated DESC customer loads and identified the portion of applicable customers in each class (i.e., those customers that have not opted out of energy efficiency programs).[111] ICF then further segmented class loads into different uses and subcategories, to which the efficiency measures could be applied to estimate cost and savings potential.

This analysis resulted in a recommended program of achievable cost effective measures that double the savings compared to the current program by 2022. The so-called expanded programs scenario serves as the basis for the 5-year action plan in the 2019 Potential Study and the Medium DSM case in the 2020 IRP.

The 2020 IRP also considers three DSM sensitivities in addition to the expanded programs / Medium DSM case, as seen in Table 29. In the Low DSM case, the expanded programs identified in the 2019 Potential Study are not pursued, and DSM continues in line with current programs. Under the High DSM case, DSM impacts identified in the expanded program are scaled up to an amount equal to 1% of customer sales from the previous year.[112] DESC further considered a DSM case developed by the SBA that assumed DSM impacts reduced customer sales by 1.25% of the previous year.

Table 29: DSM Scenarios included in 2020 IRP

DSM Scenario	Description
Low DSM Case	DSM grows to 0.4% of retail sales by 2024, equivalent to DSM program levels without actions identified in 2019 potential study
Medium DSM Case	DSM grows to 0.7% of retail sales by 2024, equivalent to expanded program scenario from the 2019 potential study
High DSM Case	DSM grows to 1% of retail sales by 2024, extrapolated from the expanded program results of 2019 Potential Study based on consultation with study authors ICF
SBA DSM Case	DSM grows to 1.25% of retail sales by 2024, provided by SBA and not supported by measures considered in DSM study

Figure 26 illustrates the impact of DSM on total sales in each model year. These energy efficiency savings were applied to DESC's long-term load forecast in the PROSYM model.[113] Incremental investments in efficiency programs drive year-over-year growth in energy savings

[110] ICF, "2019 Potential Study" pg. 9

[111] ICF, "2019 Potential Study" pg. 21

[112] This assumption was developed in consultation with ICF but was not analyzed as a scenario in the 2019 Potential Study.

[113] CRA did not independently review the short term load forecast which was used for years 2020 and 2021 of the IRP. Based on our interviews with DESC experts Joseph M. Lynch and Joseph Stricklin CRA understands that the short term forecast was developed through a different process that includes the impacts of energy efficiency. CRA confirmed that the implementation of DR in the long-term forecast is consistent with this explanation.

through 2029. In 2030 and later years, DESC continues to operate the expanded programs, but additional investments reflect replacement of measures installed in the 2020-2029 period to continue energy and peak savings associated with those programs. Overall, total savings in 2029 and later model years range from 560 GWh in the Low DSM case to 1,800 GWh in the SBA case, or between 2% and 7% of estimated 2029 generation.

Figure 27 and Figure 28 illustrate the impact of the DSM sensitivities on firm peak demand in summer and winter, respectively. As with energy, total savings plateau starting in 2029. Summer savings in 2029 range from 130 MW to 450 MW, or between 3% and 9% of estimated 2029 summer peak requirements. Winter savings range from 130 MW to 430 MW, or between 3% and 9% of estimated 2029 winter peak requirements.

Figure 26: Cumulative Energy Efficiency Impact on Total DESC Sales

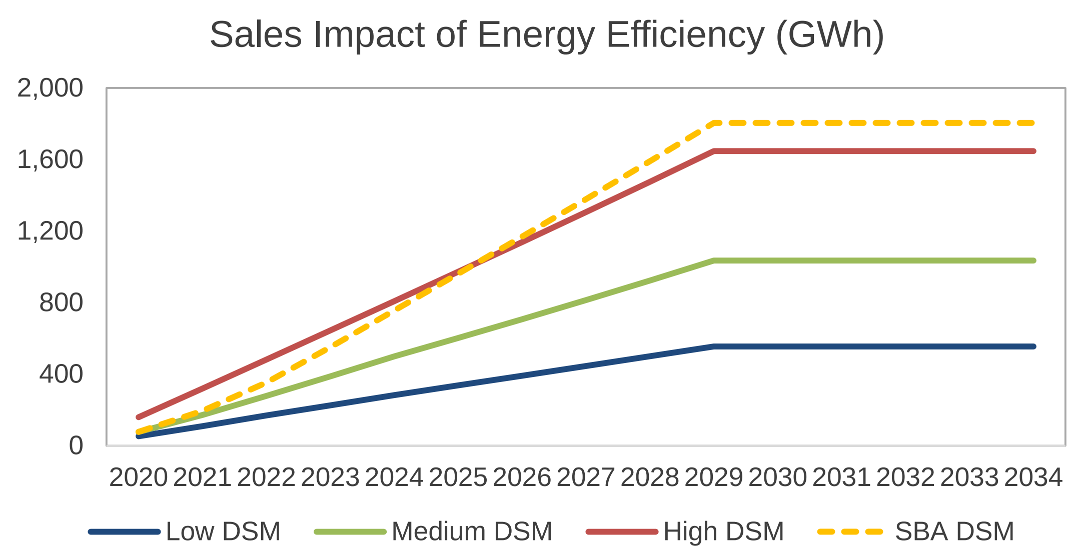


Figure 27: Summer Peak Savings from Energy Efficiency Programs in the 2020 IRP

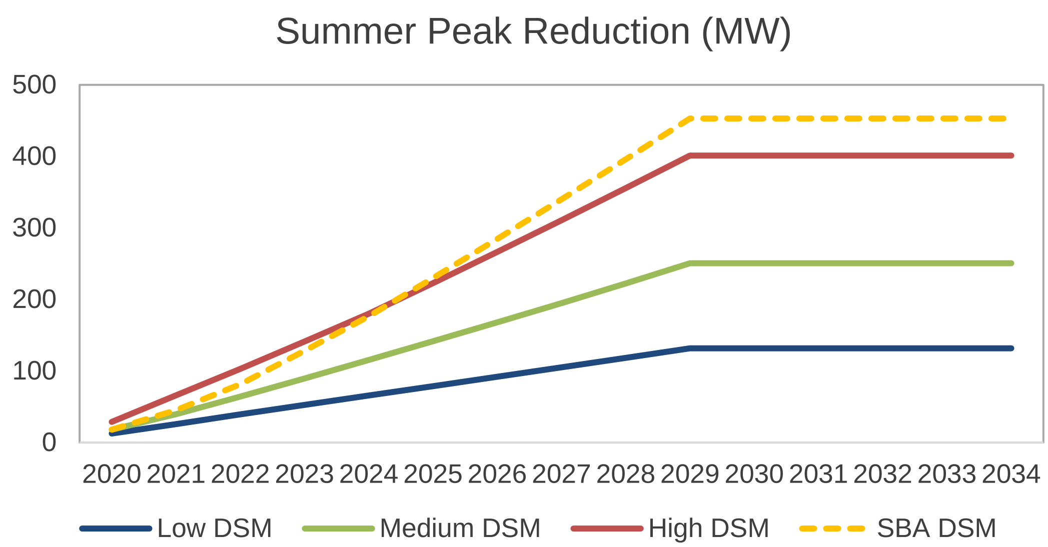
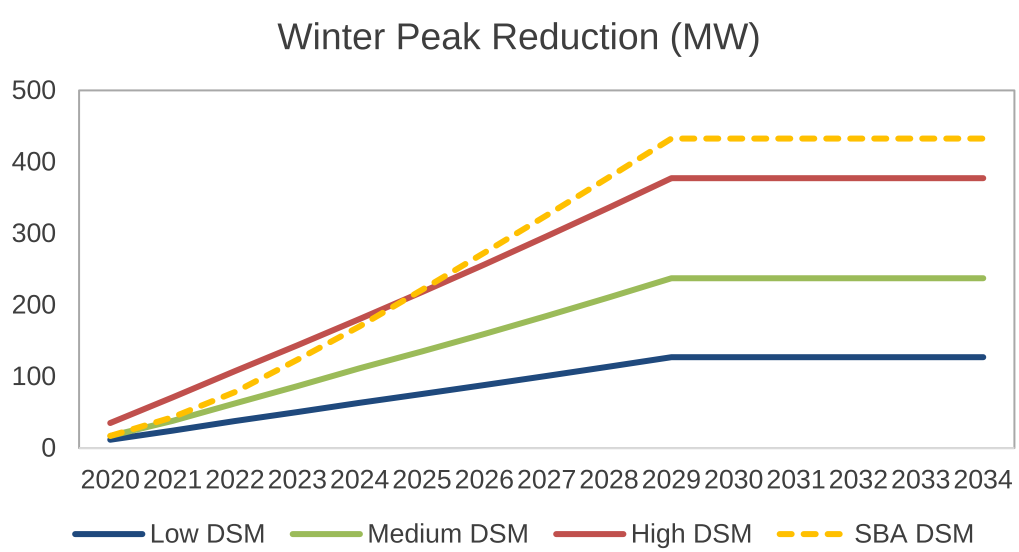


Figure 28: Winter Peak Savings from Energy Efficiency Programs in the 2020 IRP



Review of Load Management

The 2019 Potential study also evaluates incremental DR activities for inclusion in the expanded program. Table 30 illustrates the measures considered in each of the major customer classes. As with energy efficiency, ICF first evaluated the composition of loads within the DESC service territory to determine the program types that could be applied. ICF then tested the range of relevant DR program types currently implemented in U.S. markets and evaluated each with a TCR test.

Rate-based initiatives, such as the modified Time-of-use ("ToU") rates, were tested using ICF's Time-of-Use Rate Evaluation Tool (ToURET) across all customer classes to determine if more aggressive pricing would result in savings beyond what the current program achieves. The ToURET model was also used to evaluate the impact of Critical Peak Pricing ("CPP") measures.

Direct Load Control ("DLC") measures that allow DESC to control thermostats and water heaters remotely were tested against all customer classes using ICF's Direct Load Control Model.

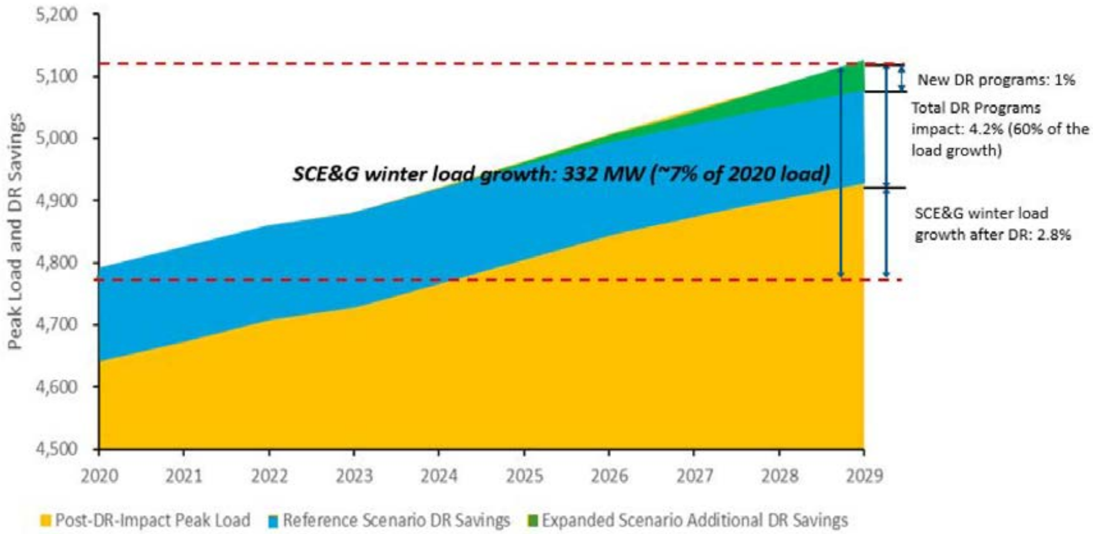
Current standby generator and interruptible programs were reviewed but not modeled under the expanded scenarios. Factors that supported this decision included the fact that the large percentage of industrial customers that would most likely participate in the offerings have already made the decision to opt-out of the current DSM programs.

Table 30: Load Management Measures Evaluated in the 2019 Potential Study

Residential	**Commercial**	**Industrial**
Time-of-use Program Direct Load Control *Smart Thermostat* *Water Heater Switch* Critical Peak Pricing	Standby Generation Program Direct Load Control *Smart Thermostat* *Water Heater Switch* Critical Peak Pricing	Interruptible Load Time-of-Use Program Direct Load Control *Smart Thermostat* *Water Heater Switch* Critical Peak Pricing

Standby generation and interruptible load programs included in the current programs are carried forward in the expanded plan without major modification. These measures make up the bulk of the DR savings estimated in the 2019 potential study, as seen in Figure 29.

Figure 29: Load Growth and Load Impact, by DR Program[114]



ToU rates, as well as a subset of commercial and residential DLC measures covering thermostats and water heater switches were found to be cost effective and included in the expanded programs forecast relied upon in the 2020 IRP. These measures, in aggregate, provide an additional 43MW of peak winter savings by 2029, beyond what can be expected from DESC's current interruptible load and standby generation programs.[115]

Confirmation that DSM plans map to described assumptions

CRA reviewed the PROSYM inputs to confirm that EE and DR impacts were modeled as described in the assumptions. Broadly, DR and EE were modeled either as capacity resources or as a load adjustment.

In all resource plans, existing and incremental DR were modeled as a capacity resource. Figure 30 shows the existing demand response that was used in all portfolios to calculate winter and summer reserve margins. Incremental DR was also applied as a supply-side resource, with impacts varying across the Low, Medium, and High DSM cases. The SBA scenario included impacts of accelerated energy efficiency, but used the same forecast of incremental DR as the Medium case. The Low case had no incremental DR. DESC provided a response to CRA's data request that demonstrated how the values for the DR were estimated, which supported the volume of load management programs assumed in the 2020 IRP.[116]

[114] ICF, "2019 Potential Study" p.49

[115] Ibid.

[116] 2020 DESC IRP pg.22

Figure 30: Existing Demand Response

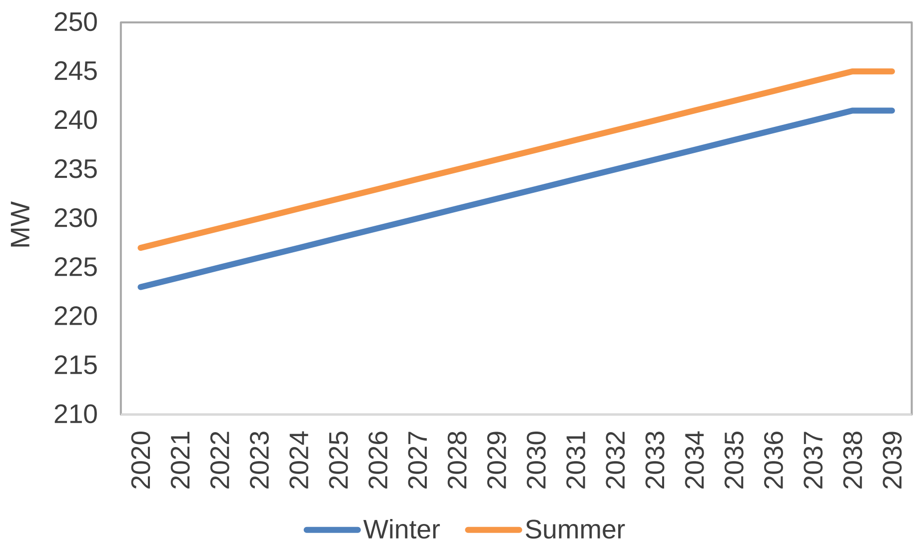
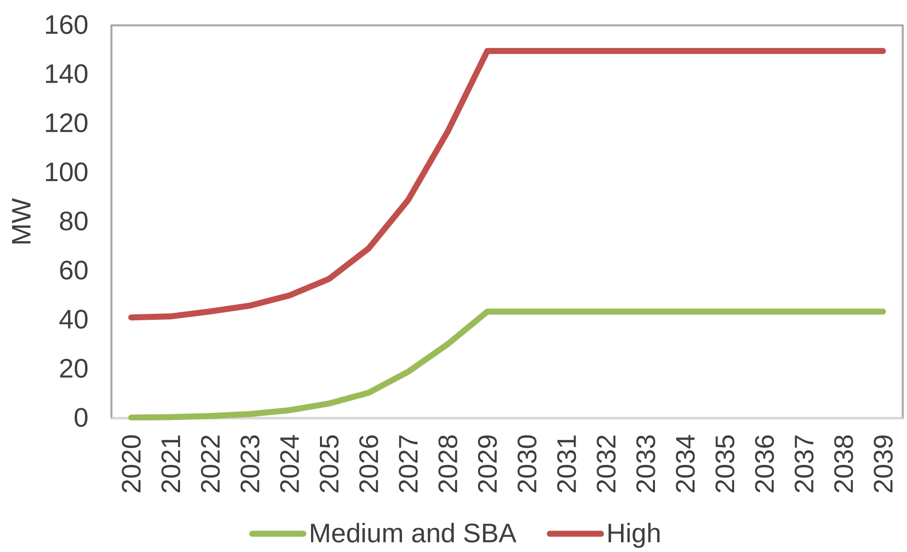


Figure 31: Incremental DR by Scenario



EE also impacted the load inputs for PROSYM. The EE impacts on gross monthly peak by scenario (Low, Medium, High, and SBA) were described in the “EE MW Savings – Summer Peak” and “EE MW Savings – Winter Peak” assumptions tables provided for CRA’s review. CRA confirmed that incremental peak savings from the ICF report and the suggested SBA adjustments were reflected in these portfolio models. While the report describes efficiency impacts beginning in 2020, DESC adjusts peak loads in the long term, starting in 2022 when the short-term forecast transitions to the long-term forecast. The adjustments were applied to monthly peak demand cumulatively, as shown in Figure 30 and Figure 31. CRA confirmed that the model inputs matched the assumptions described in the ICF report by reviewing the Gross Monthly Peak load in each of the 29 resource plan files.[117]

Confirmation that DSM impacts applied properly to meet RM requirements

CRA reviewed the DESC expansion plan files to confirm that DSM, EE, and DR impacts were applied to the calculation of DESC system summer and winter reserve margins. The load used to calculate the reserve margin was based on the Gross Monthly peak, which was inclusive of EE impacts. Each resource plan also included a separate line item for the relevant DR assumptions, as shown in Figure 30 and Figure 31. Based on this review, CRA has confirmed that the DSM assumptions were applied properly to Resource Plans 1-8 for High, Medium, and Low DSM and SBA Plans 1-5.

7.7. Model Input and Output Validation

7.7.1. Fuel Cost Assumptions

CRA has reviewed DESC's modeling results to ensure that the fixed and variable fuel costs for existing DESC coal and gas units and new gas units are reasonably represented. Figure 32 illustrates DESC's commodity fuel and variable transport costs for existing and new gas units modeled in the 2020 IRP. Gas commodity fuel costs are almost identical between new and existing gas units, which is reasonable in CRA's view, as all gas units see the same input fuel cost. Variable gas transportation costs at new plants are projected to be lower than at existing DESC plants. This is because the forecast of variable costs for the existing units reflects actual unit cost and situational price premiums paid due to the limitations of the current gas infrastructure. DESC assumes that any new gas units will require expansion of the gas delivery infrastructure, as reflected in the fixed cost comparison shown in Table 31. New gas units are expected to have lower transportation costs than existing units because it is assumed they will be sited where transport is less constrained.[118] Because these units are paying a premium for gas capacity expansion, this assumption is reasonable.

[117] CRA found that the inputs matched the relevant table in the input file '2020 IRP Loads with DSM Scenarios (012420).xlsx.'

[118] May 26 interview with James Neely & Eric Bell

Figure 32: Gas Unit Fuel Costs – Base Gas View

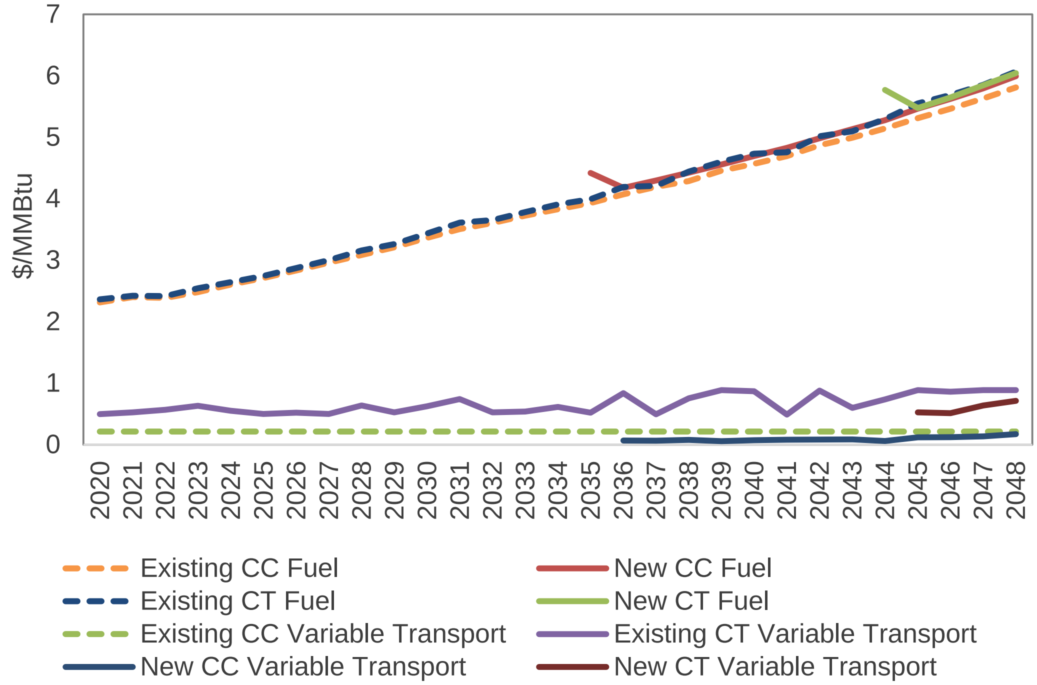
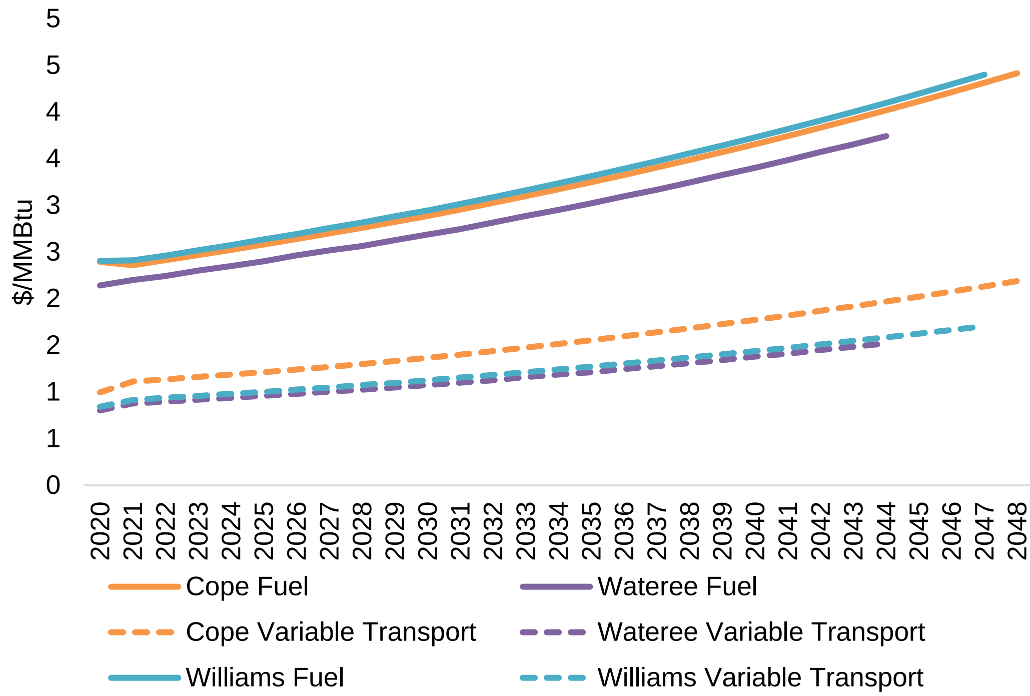


Figure 33 illustrates the fuel and transportation cost assumptions for the DESC coal fleet. Cope, Williams, and Wateree all primarily burn Central Appalachian ("CAPP") coal. Cope and Williams tend to burn lower-sulfur coal, while Wateree burns higher-sulfur coal, which is modestly less expensive as illustrated in the market prices in Figure 34. The coal cost forecasts in DESC's 2020 IRP are based on existing contracts at the units. Therefore it is reasonable that fuel commodity costs would vary slightly between units, reflecting differences in contracts and types of coal burned. In terms of variable transport costs, it is reasonable that coal units would see a higher variable cost of transport than gas units, which tend to have more of a fixed cost structure.

Figure 33: Coal Unit Fuel Costs



In addition to fuel and variable transport costs, DESC fossil units incur a fixed fuel charge. For DESC's coal units, these range from \$9/kW-yr (Wateree) to \$16/kW-yr (Williams), with Cope falling in between the two, at \$14/kW-yr. For coal units, these costs are incurred moving coal from the mines where it is purchased to the power plant, typically via rail or barge. Actual transportation costs vary by mine and contract. These figures grow annually at the rate of inflation. For gas units, DESC assigns fixed fuel costs to new units that are approximately three times the cost applied to its current units, on a dollar-per-kilowatt basis. Costs are higher for new units due to constraints on gas delivery infrastructure. The higher fixed costs represent the cost of expanding or building new gas delivery capacity to meet power plant demand. DESC assumed that all new gas units would require an expansion of gas delivery infrastructure in order to receive firm transportation.

Table 31: Fixed Fuel Charges for DESC Gas Units

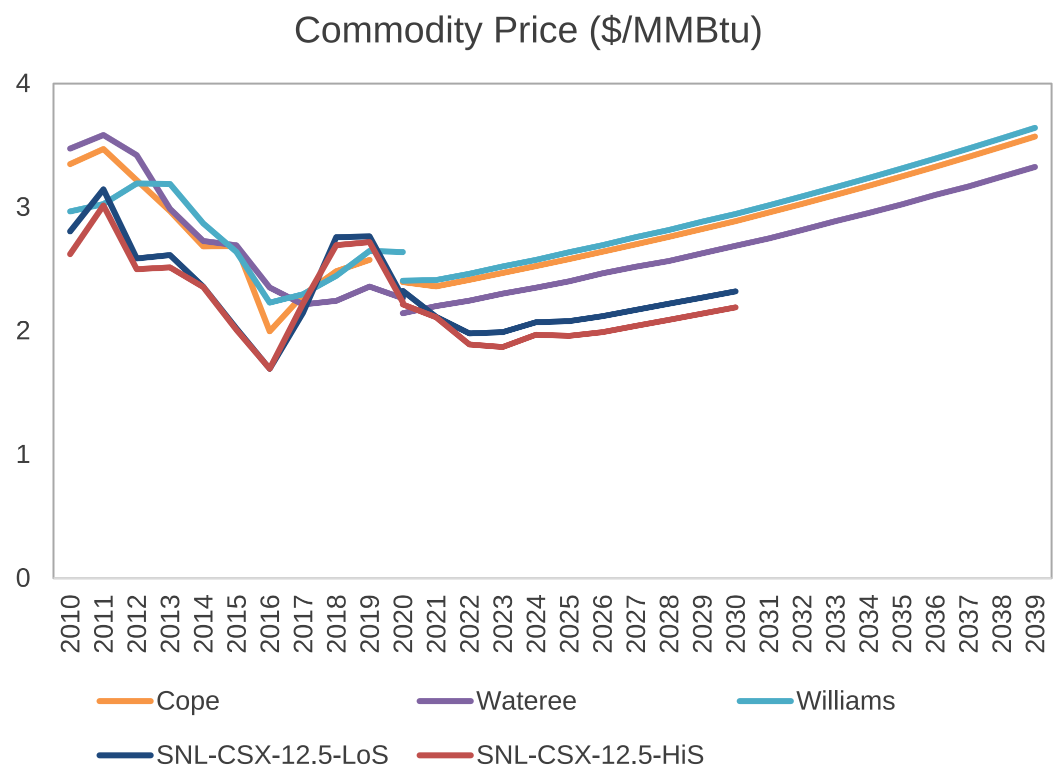
	Fixed Fuel Costs (\$/kW)
Jasper CC	21.05
New CC	66.44

DESC ran three gas price scenarios, as described in section 7.5, and the commodity fuel costs vary by scenario accordingly. Variable and fixed transport costs did not vary by scenario. Coal commodity prices also did not vary by scenario.

Review of the Coal Forecast Assumptions

As described in the previous section, Cope, Williams, and Wateree all primarily burn CAPP, with Wateree tending to burn higher-sulfur coal than Cope and Williams. CRA evaluated the commodity forecast from the 2020 DESC IRP by comparing it with historical data and publicly available SNL forecasts for high and low sulfur content CAPP coals, as illustrated in Figure 34.[119]

Figure 34: Comparison of Coal Price Forecasts

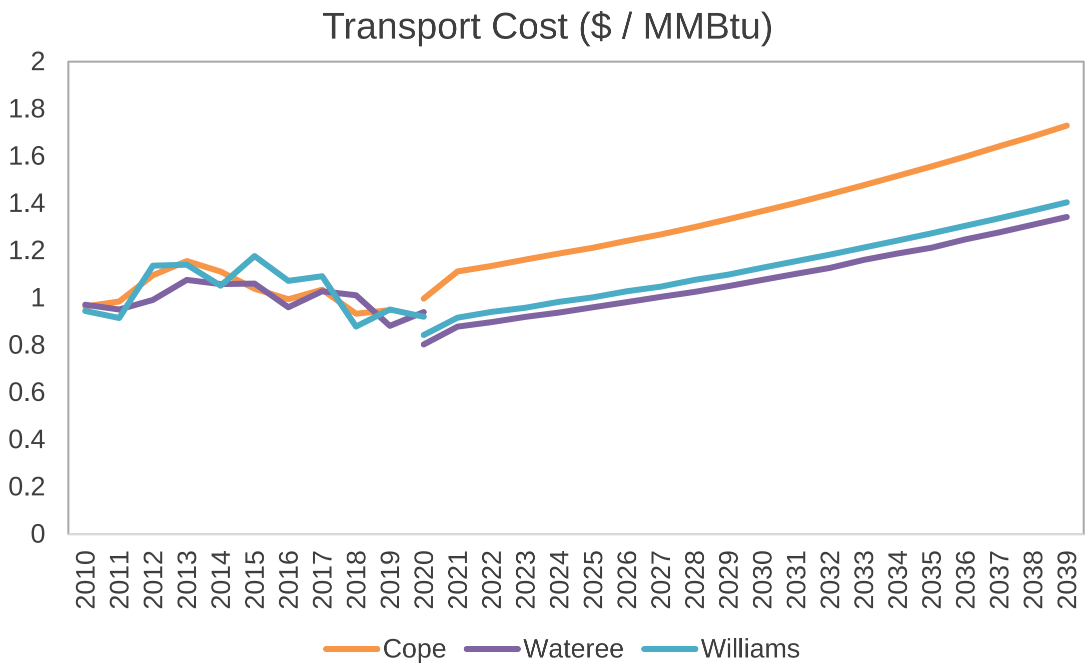


The price premium observed in the DESC forecast relative to the SNL forecast is consistent with the premium observed in the historical data through 2018. CRA views these commodity price forecasts as reasonable if a bit high relative to recent futures prices.

Coal transportation costs were estimated separately for each of the DESC units. Figure 35 compares the forecasted transportation cost for the DESC units with historical estimates taken from SNL. For Williams and Wateree, projected values start modestly lower than recent estimates, while Cope shows a modestly higher cost. Note that transportation costs grow modestly faster than commodity prices in the DESC forecast. CRA's analysis of the historical data shows them to be reasonable.

[119] SNL Coal Central Appalachia Big Sandy/Kawha River CSX 12500 btu/lb 1.2 lb/mmBtu Sulfur; SNL Coal Central Appalachia Big Sandy/Kawha River CSX Prompt Quarter Coal 12500 btu/lb 1.5 lb/mmBtu Sulfur

Figure 35: Transportation Cost Review



7.7.2. Reserve Margins Met with Each Resource Plan

CRA reviewed all of DESC's resource plans to confirm that all plans met the base reserve margin requirements. The first step in this validation was to review the seasonal unforced capacity ratings of DESC's existing resources, as shown in Table 32.

CRA then compared these ratings with the reserve margin requirements across time and across portfolio plans. The plans reviewed include RP1-8 for Low, Medium, and High DSM, and SBA RP1-5.

Peak load in summer 2020 is expected to be 4,816 MW, implying a 17.6% base reserve margin. Winter peak load in 2020 is 4,891 MW, resulting in a 20.9% base reserve margin.

Table 32: Existing Supply Seasonal Unforced Capacity (UCAP)

Resource Name	Fuel	Winter UCAP (MW)	Summer UCAP (MW)
Wateree	Coal	684	684
Williams	Coal	610	605
Cope	Coal	415	415
McMeekin	Gas	250	250
Urquhart	Gas	96	95
V.C. Summer	Nuclear	662	650
Urquhart 1, 2, 3	Gas	48	39
Urquhart 4	Gas	49	48
Coit	Gas	36	26
Parr	Gas	73	60
Williams	Gas	52	40
Hagood 4-6	Gas	141	126
Urquhart CC	Gas	484	458
Jasper CC	Gas	924	852
CEC CC	Gas	571	504
Neal Shoals	Hydro	4	3
Parr Shoals	Hydro	12	7
Stevens Creek	Hydro	10	8
Saluda	Hydro	198	198
Fairfield PS	Hydro	576	576
SEPA Contract	Other	20	20
Total		**5,915**	**5,664**

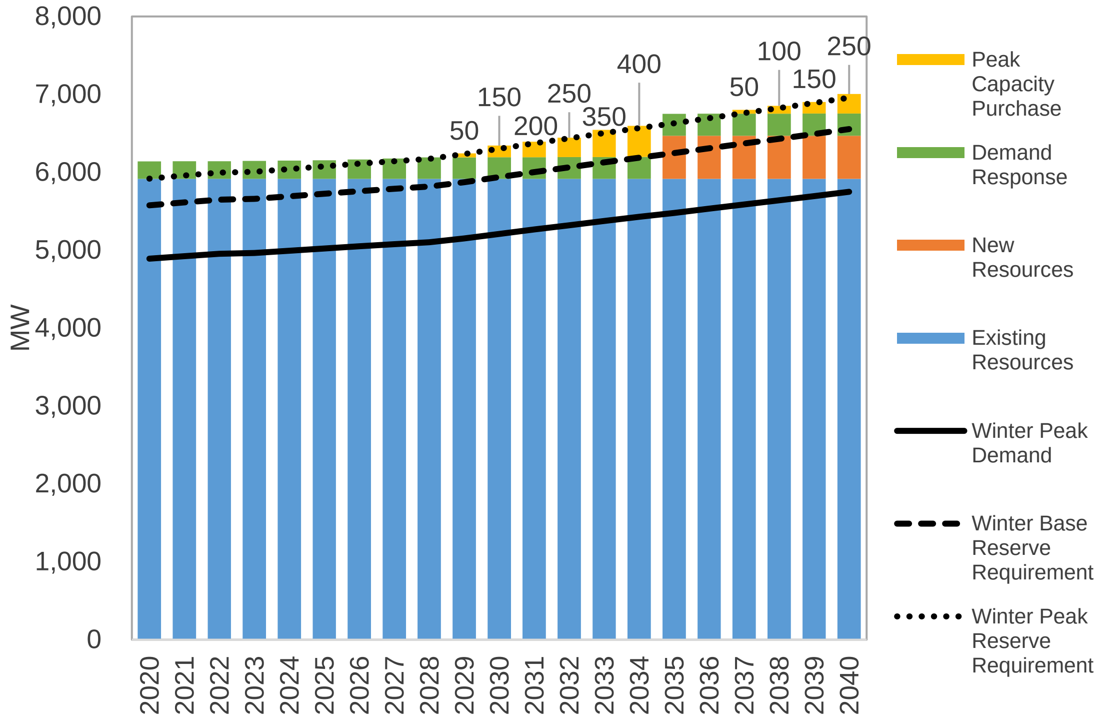
The existing resources were found to satisfy the base reserve requirements of 12% and 14% for summer and winter, respectively, in 2020. Going forward, CRA confirmed that all replacement resources in Resource Plans 1-8 and SBA Resource Plans 1-5 were adequate to fill capacity gaps left by any retirements, load growth, and operation of existing units, and that the reserve margins never fell below 12% in summer and 14% in winter.

CRA also reviewed DESC expansion plan files for Resource Plans 1-8 (for Low, Mid, and High DSM) and SBA Resource Plans 1-5 to confirm that they meet the peaking reserve requirements of 14% in summer and 21% in winter. In addition to the permanent supply resources, DESC used demand response and capacity purchases to meet the peak requirement.

Figure 36 graphically represents base and peaking reserve margin compliance for Resource Plan 1 under the Base DSM scenario. The blue bar represents existing permanent supply, and the orange bar represents new permanent resources (in this plan, a 553 MW CC). The green bar represents demand response, as summarized in Figure 30 and Figure 31. These three components together satisfy the base reserve requirement of 14% in all years. In years when the 21% peak reserve margin is not met with permanent supply and demand response, one-year capacity purchases were allowed in 50 MW increments. These 50 MW capacity purchases were included in the revenue requirement calculation, costing $4.50/kW-month and $4.05/MWh (in 2018$, escalating at 3% per year), between December and February only. This cost is based on a gas peaker. As a portion of total portfolio cost, the cost of these winter peak capacity purchases is small.

The yellow bar represents these peak capacity purchases for Resource Plan 1.

Figure 36: RP1 Base DSM Peaking Reserve Margin



CRA reviewed each of the 'EPLAN' files to confirm that the peak requirements were met for all resource plans and scenarios. As the winter requirement is stricter than the summer requirement, the summer peak requirement is also met in all portfolios.

7.7.3. Confirmation that PROSYM Outputs Correctly Reflect Model Inputs

CRA reviewed several key outputs from the PROSYM model and revenue requirement models to ensure that they accurately represent the inputs to the model. While CRA is not able to independently evaluate each input from each portfolio under each scenario, CRA performed sampling of various outputs to ensure they matched the inputs stated by DESC in its IRP. For example, CRA plotted the fuel cost outputs from the various gas price scenarios for DESC Plan 1. Figure 23 shows the average gas price for DESC gas units in Plan 1, under the three gas price scenarios. These annual cost trajectories match the gas price forecast shown in DESC's IRP document. In addition to fuel prices, CRA reviewed the capital cost calculations from DESC's revenue requirement spreadsheets, and was able to confirm that the annual capital costs used in these sheets match the capital cost table shown in DESC's IRP document.

7.7.4. Reasonableness of Levelization Calculations

CRA reviewed the levelization calculations used by DESC to calculate the relative costs of each portfolio under the various scenarios. To calculate a levelized system cost, DESC uses an annuity function to calculate a levelized annual revenue requirement. Using DESC's weighted average cost of capital of 8.50%, DESC discounts forty years of annual revenue requirement (annual output from 2020-2059) and levelizes it into one single annual number. By levelizing forty years of revenue requirements into one number, DESC has created a value that, when multiplied by forty, is equivalent to the net present value of those forty years of annual revenue requirements. This methodology is similar to taking the net present value of annual revenue requirements ("NPVRR"), which is a commonly accepted metric used in many utility IRPs. DESC's levelized methodology is the same principle as an NPVRR, translating a forecast of annual costs it into one single annual number. CRA has reviewed this calculation and deems the overall methodology to be reasonable.

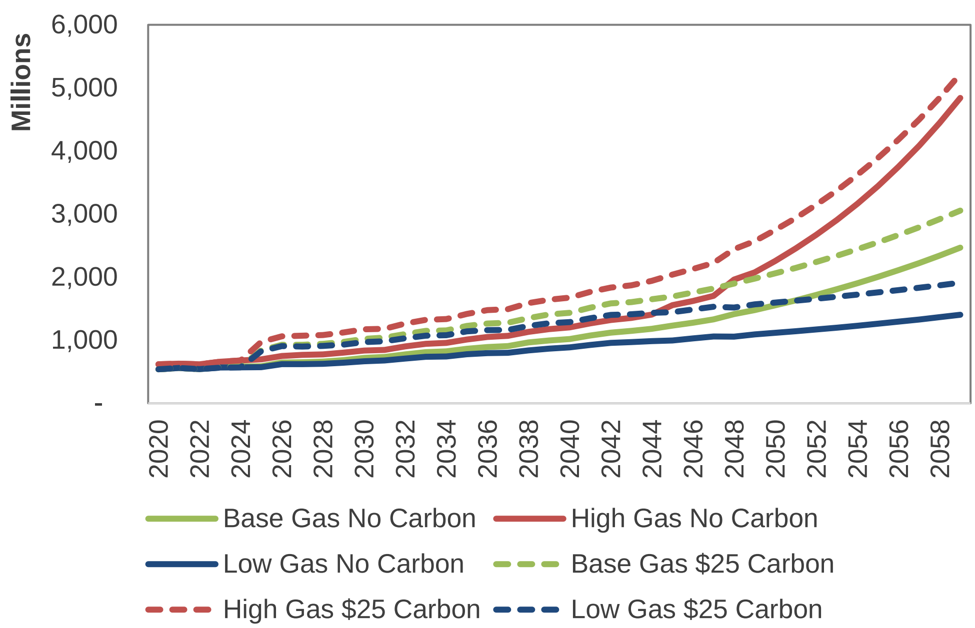
7.7.5. Reasonableness of Revenue Requirement Outputs

CRA has reviewed the revenue requirement summaries, and their component parts, for each portfolio under each scenario that DESC analyzed. CRA has reviewed the major differences between portfolios under different scenarios to determine, based on the inputs to each portfolio and scenario, that the revenue requirement results are generally accurate and reasonable. The remainder of this section provides a sampling of tests performed by CRA to validate the reasonableness of calculations and model outputs.

Variable Cost Differences by Portfolio

To analyze the variable costs for each portfolio, CRA reviewed the fuel costs, variable O&M costs, and emissions costs that DESC calculated for each portfolio under each scenario. As an example, Figure 37 shows the total variable costs for Plan 2 (DESC's preferred plan) under the six variations of gas and carbon prices. Total variable cost includes fuel, variable O&M, and emissions (namely carbon) for DESC's total portfolio.

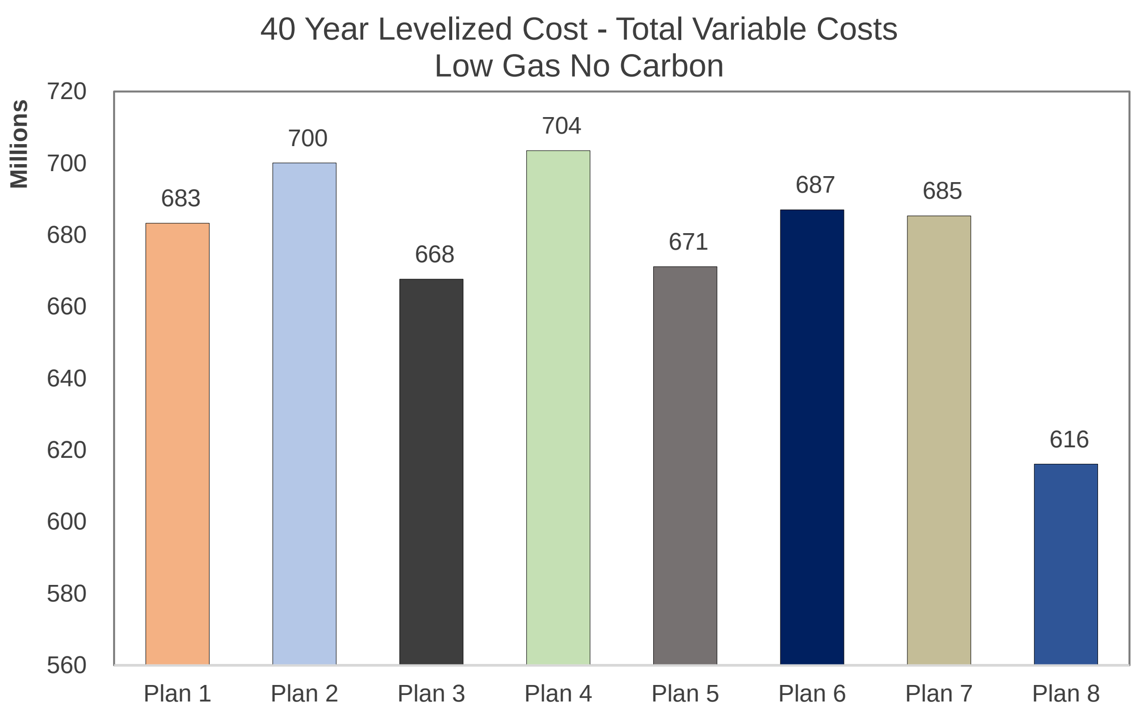
Figure 37: Total Variable Costs for Resource Plan 2

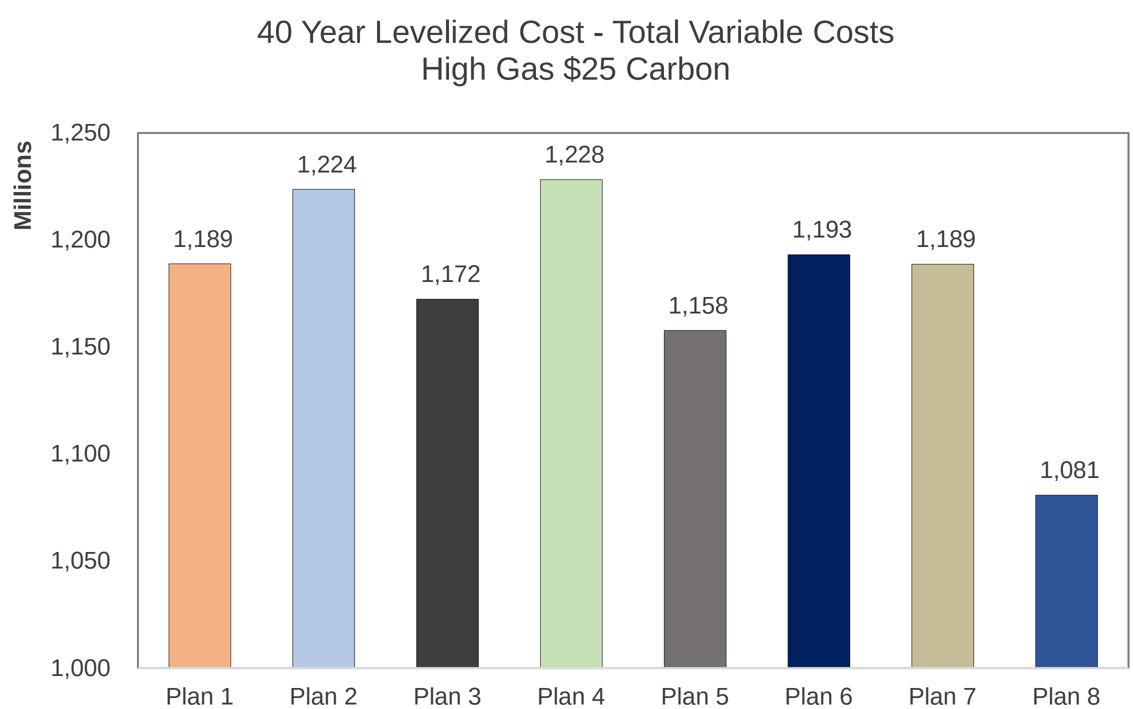


The ordering in the graphic above appears to be reasonable and intuitive. The lowest variable costs for the portfolio are observed in the scenario with low gas prices and no carbon price. DESC has a gas-heavy existing portfolio, and Plan 2 adds natural gas-fired ICTs to meet capacity needs in the future, so low gas prices would be a net benefit to the variable costs of the portfolio. The highest costs occur in the scenario with high gas prices and a carbon price imposed on DESC's portfolio. This general ordering of cases is the same for all eight of DESC's resource plans as well as the SBA portfolios, with some slight variations in the SBA portfolios depending on timing of new renewable additions. It should be noted that after 2048, total variable costs for each portfolio begin to escalate at an increasing rate. DESC's fundamental forecasts for fuel, power prices, and other variables only extend until 2049, and DESC needs to employ an "end-effects" extrapolation to produce forty year NPVRR figures. This is a common approach for many utilities, and CRA believes it is reasonable.

In addition to reviewing the variable costs of each portfolio under difference scenarios, CRA analyzed the *relative* positioning of each portfolio under various scenarios. Figure 38 shows the forty-year levelized total variable costs for each of the eight DESC portfolios under the Low gas - $0 carbon price case and the High gas - $25 carbon price case. These two cases represent the market scenarios that resulted in the lowest and highest system costs, respectively. The relative ordering of the portfolios are intuitive and reasonable. In the Low gas - $0 carbon price scenarios, plans that retain coal and add more gas generation (i.e., Plans 1, 2, and 4) have higher total variable costs. Plans that add more solar and battery generation relative to gas generation (i.e., Plans 5 – 8) have relatively lower variable costs. Under cases with a High gas price outlook and a $25 carbon price, the overall rankings of the portfolios are similar. However, Plan 3 is lower cost than Plan 5 under this case due to the early retirement of the Wateree units.

Figure 38: 40-Year Levelized Cost Summaries





New Generation Costs Differences

To evaluate the range of difference in new generation costs under the DESC portfolios, CRA compared the cost of new generation capacity under DESC Plan 2, which is the preferred plan, with DESC Plan 8, which retires the most current DESC-owned capacity and replaces it with new resources. It is reasonable that Plan 8 had significantly more new generation costs than Plan 2 because DESC assumes early retirement and replacement of Wateree and Williams under Plan 8. Plan 8, appropriately, did not include the cost of environmental upgrades included in Plan 2 because these units retire in advance of the compliance deadline.

Figure 39: New Generation Capacity Costs – Plan 2 vs. Plan 8

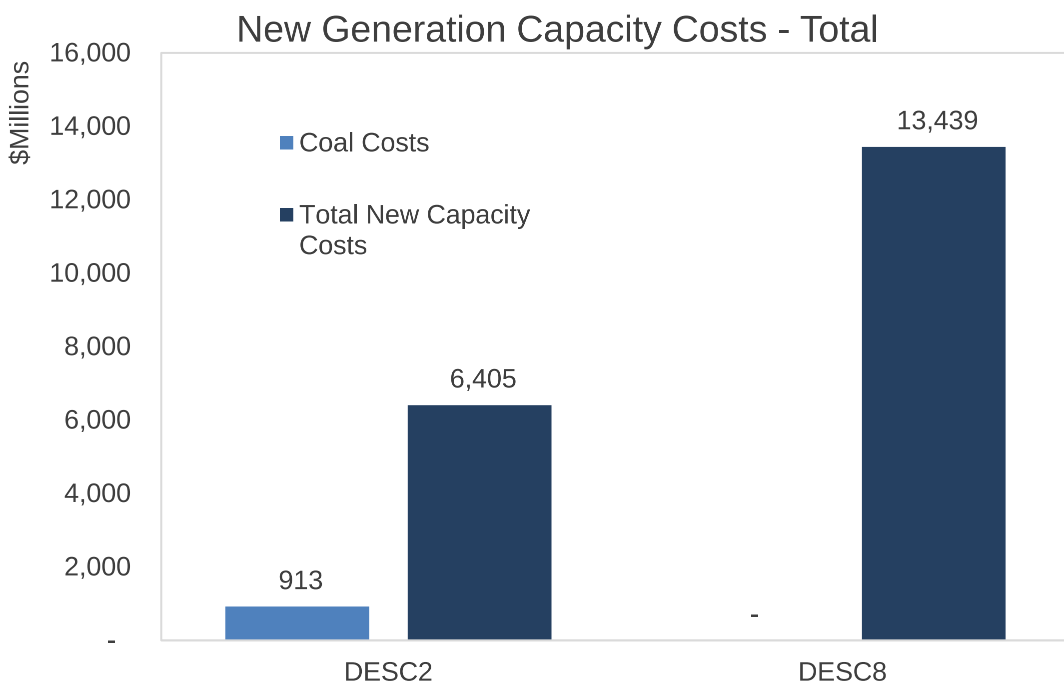
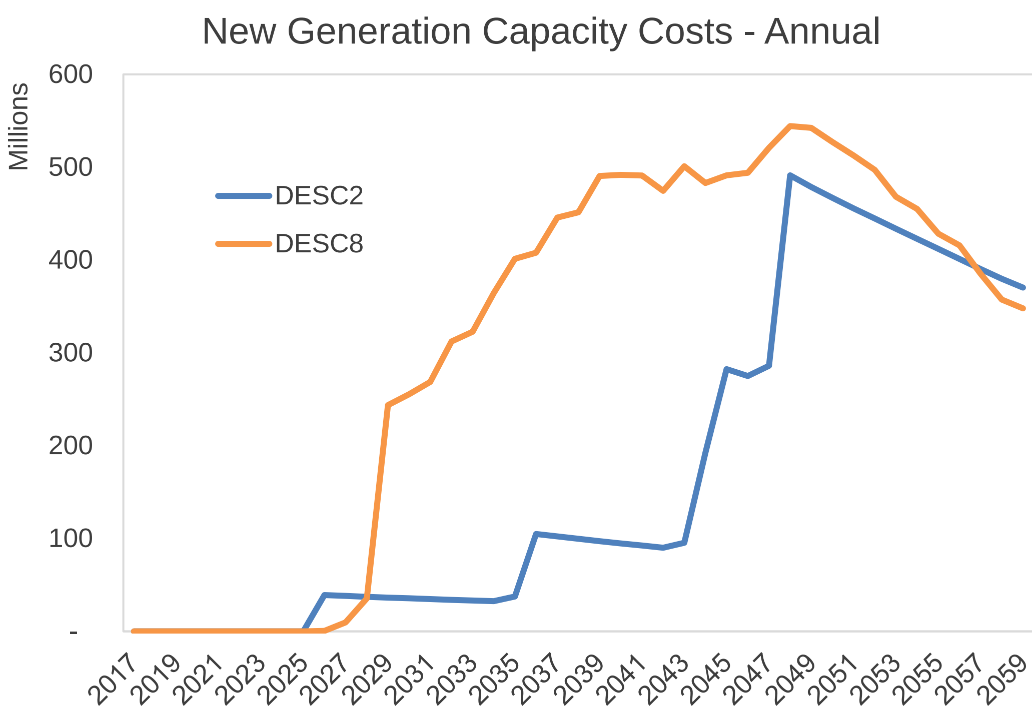


Figure 40: Annual New Generation Capacity Costs – Plan 2 vs. Plan 8

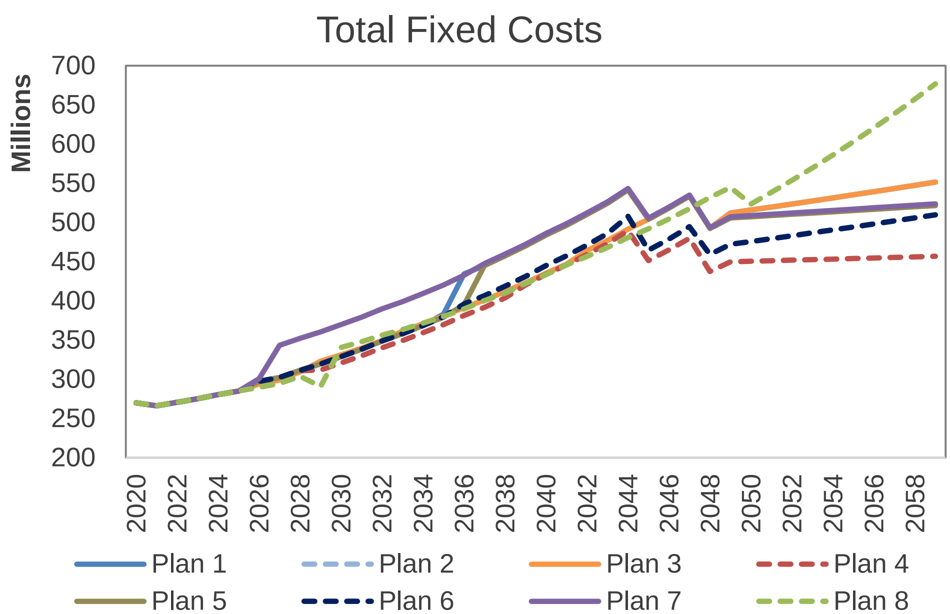


Capacity cost expenditures for new resources were more than $6 billion greater under Plan 8 than Plan 2 over the forecast period, illustrated in Figure 40. This outcome is reasonable given that almost 1,300 MW of existing capacity is retired in 2028 and replaced with new resources under Plan 8. Importantly, Plan 8 does not include the $900 million in capital expenditures required to retrofit existing coal units with environmental upgrades. The annual spending schedule for new capacity reflects both the timing and size of new generation capacity additions. In Plan 8, capacity cost expenditures increase dramatically in 2028 and 2029, as new CC and ICT plants are added. The new capacity costs rise in later years when solar, storage and additional ICTs are added through 2048. Under Plan 2, new capacity cost expenditures are lower than in Plan 8, and further spaced out. Plan 2 projects new spending to start in 2026, as environmental upgrades for DESC's existing coal plants are added. Plan 2 does not add any major further incremental spending until an additional ICT unit is added in 2035 to meet reserve margin requirements.

Fixed O&M Cost Differences

To analyze the fixed costs for each portfolio, CRA reviewed the fixed fuel costs and fixed O&M costs that are calculated for each portfolio. Figure 41 shows the total fixed costs, which include both fixed fuel cost and fixed O&M cost, by portfolio under the Base gas - $0 carbon price scenario.

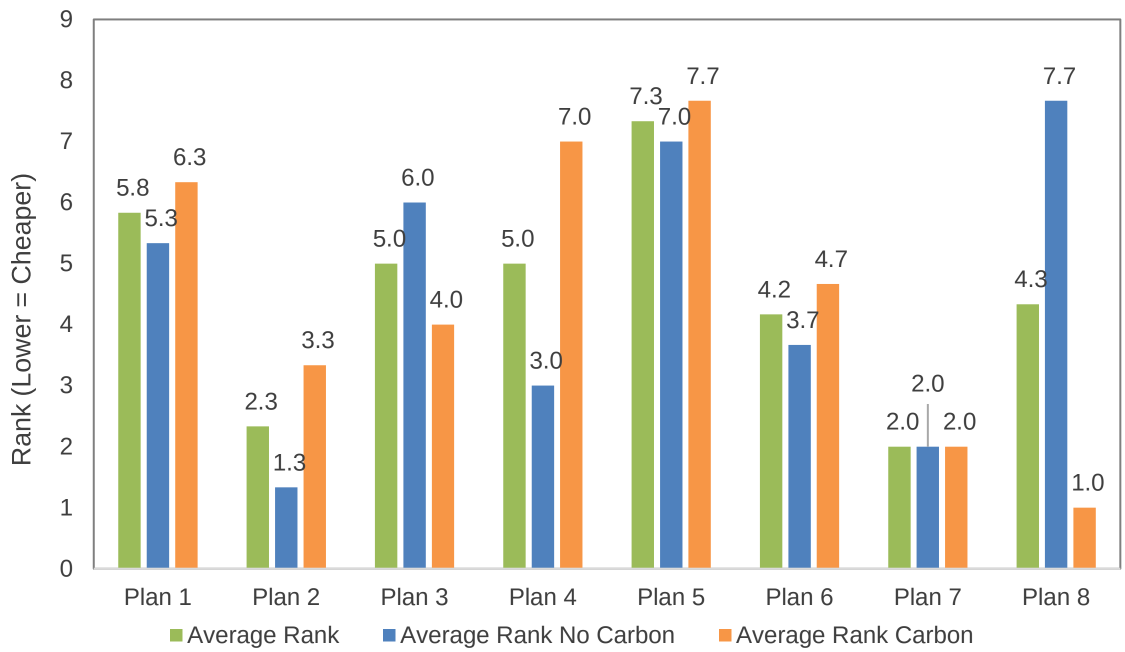
Figure 41: Total Fixed Costs by Plan



The ordering is reasonable and intuitive. The values in Figure 41 include fixed costs for both existing and new units. Therefore, the timing and size of fixed O&M cost is related to the amount and type of new resources built under each plan, which in turn reflects the amount of early retirements assumed for the current DESC portfolio. Plan 7 adds 400 MW of solar PPA and 100 MW of battery PPA between 2026 and 2027, which causes the fixed costs to increase. Plans 1 and 5 both add large combined cycle units in the 2035 to 2036 timeframe, which contributes to a rise in fixed costs in those years. Plan 8 shows an initial drop in fixed costs when it retires coal units in 2028. Fixed costs increase as those units are replaced with a combined cycle and ICTs.

Levelized NPV Results

Figure 42: Levelized NPV by Plan – Rank Order



CRA reviewed the overall costs of each plan under each of the gas and carbon scenarios, as measured by the levelized net present value calculation used by DESC. Figure 42 illustrates the average ranking of the eight DESC resource plans on a levelized cost basis across all 64 simulations and compares the rankings across the zero dollar and $25 carbon price views separately. These figures represent the average rank, 1 through 8, of the levelized system costs of each resource plan with 1 representing the lowest cost portfolio. For example, Plan 8 has a composite rank of 1.0 across the $25 carbon price scenarios, which means that it was the least costly portfolio under every load and fuel outlook when the $25 carbon price view was included. This result is reasonable, as Plan 8 is described as the low carbon plan in the IRP.[120] Plan 2 shows a composite score of 1.3 under the set of $0 carbon cases, which illustrates that it was the least costly plan across most of the load and fuel price scenarios when the CO_2 price was zero dollars.

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